August 30, 2017

Via email: SiteCSubmission@bcuc.com

Commission Secretary
British Columbia Utilities Commission
Sixth Floor, 900 Howe Street
Vancouver, BC V6Z 2N3

Attention: Patrick Wruck

Dear Mr. Wruck:

Re: Site C Inquiry – Submissions of Prophet River First Nation and West Moberly First Nations

We are counsel for Prophet River and West Moberly First Nations (the "Treaty 8 Nations"). As you are aware, the Treaty 8 Nations have been extensively involved in the review of the Site C Project since 2011. The Nations have produced several reports that speak directly to the issues that the Commission is tasked with considering. We have included copies of these reports and submissions for your reference. We understand that once we have access to the submissions of BC Hydro and the Commission’s Preliminary Report that the Treaty 8 Nations will have the opportunity to make further submissions.

The purpose of this letter is to provide a summary of the Treaty 8 Nations’ position with regards to the questions facing the Commission.

1. Cost

For several years, BC Hydro stated that the budget for Site C was $7.9 billion and they were confident in that number. They provided only a summary of construction costs.
There was no independent review of the costs of the Project. KPMG produced a four-page letter reviewing BC Hydro's methodology, nothing more.¹

The Joint Review Panel (the "JRP") could not determine the accuracy of the costs, need for the Project and rejected the purported regional benefits of the Project. While the JRP stated that "Site C will seem cheap one day", this was not a finding of the panel. A $9 billion project may seem cheap if it is amortized over 80 years (which is the current plan - project will be paid off in 2094). BC Hydro's position is that if Site C lasts 100 years, at some point in the future it will pay for itself. Thus the statement must not be taken as a conclusion of the Panel, but a statement that if amortized long enough, Site C may someday seem cheap. While the statement seems superficially attractive, to paraphrase the line from the movie Field of Dreams - "if you build it they will come", it has not been borne out. Unfortunately, demand is not materializing and the Liberal government has been offering inducements and subsidies to industry to drive demand.

The $7.9 billion budget was the number they put forward to the JRP. The JRP concluded that it could not conclude on the likely accuracy of the Project costs and recommended a referral to the BCUC (Recommendation 46). In addition, the Project that was reviewed by the JRP was to have a 70/30 debt to equity ratio. Several participants, both during and after the hearings questioned the veracity of BC Hydro's cost estimates. They were right.

Two months after issuing the Environmental Assessment Certificate, the Province made a Final Investment Decision (the "FID") to proceed with Site C, but the cost had ballooned to the tune of $900 billion, without a shovel being put in the ground and BC Hydro would be providing no equity – the Project would be financed with 100% government debt. As a result of these two significant changes, any comments by the JRP about Site C being the "least expensive" option no longer are true.

Without a requirement to provide any financial return – because there is no equity with which to provide a return – the unit energy cost can be decreased, but this is the equivalent of a mirage.

The JRP concluded that such distortion should not occur for Site C:

Yet a principal reason private power producers face higher costs of capital is that they bear most performance risks. In BC Hydro's case, those risks are no less real but are borne by the customer or taxpayer, not BC Hydro. This is no reason to artificially reduce BC Hydro's [Weighted Average Cost of Capital], especially if it is to be used as a surrogate for the [Social Discount Rate].

¹ KPMG Commentary Letter.
Further, BC Hydro defined its WACC as based on a supposed average of 80 percent debt and 20 percent equity. The former is cheap—it is, after all, guaranteed by a triple-A entity with taxing powers—and the latter is shadow-priced by the return on equity BCUC allows to Fortis, a private competitor. But BC Hydro’s equity is largely fictional. It is only “deemed” to have equity; in fact it has deferral accounts. Between the EIS and the IRP, the definition went from 80:20 to 70:30 — and the WACC declined. Such an accounting marvel should not be allowed to drive choices that would affect the B.C. economy and landscape for many decades.²

In BCUC hearings a representative of BC Hydro confirmed that the Province expects zero return on investment on Site C for 70 years. Dr. Harry Swain, Chair of the JRP, has opined that BC might be able to recover $2 billion of the $9 billion projected cost over the life of the Project.

2. Need

In spite of a currently large energy surplus, BC Hydro took the position that there was an urgent need for Site C to be operational by 2024. The JRP rejected these claims finding that some power from Site C may be needed by 2028.

While it is possible that there may be a need for some power in 2028, there will be a loss of at least $800 million over four years (likely at least seven years) as such power will have to be exported. It is likely much greater losses given demand has been flat for 10 years and will be so for the foreseeable future. Given that a liquefied natural gas sector has not materialized, it is more likely that the No LNG scenario – no power until 2033 at the earliest, the end of the JRP review period – is the most likely scenario.

Importantly, the JRP identified significant restrictions regarding what they could consider “existing resources” in this calculation. Two of note, the Canadian Entitlement, which is approximately 1,300 MW, under the Columbia River Treaty and the Burrard Thermal Plant, at 900 MW are equivalent to two Site Cs. Neither resource is considered under the Clean Energy Act as a resource that BC Hydro can draw upon for domestic purposes. The Treaty 8 Nations wrote to Ministers Bennett and deJong prior to the FID setting out a portfolio, including the Canadian Entitlement that is at least $2 billion cheaper than Site C ($3 billion with the $9 budget).³ We enclose a copy of that letter for your reference.

The JRP rejected BC Hydro’s need calculations and recommended they construct a reasonable long-term pricing scenario and that this be reviewed by the BCUC prior to construction (Recommendation 47). That of course, did not happen.

Site C will produce power at a minimum of $100 MW, notwithstanding the amazing accounting marvel they have performed, raising the cost of the Project by almost $1 billion, while bringing down the cost per MW. Site C power will have to be exported for many years, certainly more than the four years initially put forward by BC Hydro.\(^4\) The current export market pays approximately $23 MW and is not likely to rise anytime soon given the current energy glut in North America. The result is the taxpayers of British Columbia subsidizing cheap power for the citizens of Alberta and California.

The JRP concluded that BC Hydro had not fully demonstrated the need for the Project on the 20-year timetable that they conducted their review.

3. Demand Moderation

Demand for power has been relatively flat the last ten years and does not appear to be increasing in the foreseeable future. However, BC Hydro has consistently overstated demand. The JRP correctly noted that Liquified Natural Gas, if developed will use natural gas to provide the power necessary for liquefaction, not hydro-electric.

Demand-side management ("DSM") is to account for at least 66% of load growth through 2020, then falls to 55% in 2033. The JRP concluded that the potential savings from DSM are likely understated. Importantly, the JRP concludes that net demand in 2033 is likely to be 65 terawatt hours, which is 4.2 TWh less than the 69.2 TWh proposed by BC Hydro. This difference represents 80% of the energy capacity of Site C.

As a result, the JRP recommended referring the load forecast and DSM to the BCUC. Again, this did not occur. However, since that time, the 2012 load forecast, on which the 2013 Integrated Resource Plan was based, has collapsed. Even BC Hydro now admits that needs for capacity and energy have shifted several years into the future.\(^5\) As a result, the 2016 load forecast is significantly lower than the 2012 load forecast which was the subject of the JRP review.\(^6\) Thus, the concerns raised by the JRP and the Treaty 8 Nations around costs, need and demand moderation are amplified by the 2016 load forecast.

Recently, as demand is not materializing, BC Hydro has all but abandoned DSM for load growth to try and make a case for Site C.\(^7\) As the JRP pointed out as any economist will

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\(^4\) Without considering the existing resources of Burrard Thermal and Columbia River Entitlement there would be at least 7 years of surplus.

\(^5\) Program on Water Governance, *Reassessing the Need for Site C* ("UBC Study") at p. 29-30.

\(^6\) UBC Study at p. 32.

\(^7\) UBC Study at p. 79-82.
opine, as rates rise, ratepayers behavior will change and they will use less power and seek out consumer products that are more energy efficient. BC Hydro’s approach was based on the assumption that DSM becomes zero by 2034. BC Hydro’s position on DSM is ridiculous and was thoroughly discredited by the Treaty 8 Nations in their letter to Ministers Bennett and DeJong, just prior to the FID. 

4. Alternatives

The Commission’s terms of reference provide you to provide a response to the following question:

Given the energy objectives set out in the Clean Energy Act, what, if any other portfolio of commercially feasible generating projects and demand-side management initiatives could provide similar benefits (including firming; shaping; storage; grid reliability; and maintenance or reduction of 2016/17 greenhouse gas emission levels) to ratepayers at similar or lower energy costs as the Site C Project?

We have addressed the demand-side management issue above. Throughout the JRP phase and leading up to the FID, the Treaty 8 Nations provided myriad alternatives that were cheaper and met the “objectives of the Clean Energy Act” in particular, the requirement that 93% of electricity be generated in BC from renewable resources. We have provided you with copies of these reports for your reference.

The Joint Review Panel was supportive of the objectives of the Clean Energy Act, but also the hypocrisy of the government in amending, clarifying or modifying such objectives when it suited their purposes, including providing an exception from the GHG targets for a liquefied natural gas industry that has yet to materialize. The Commission should also not feel so constrained by these objectives.

The 93% requirement is curious, and in the Treaty 8 Nations’ submission was geared to render Site C a fait accompli. By disallowing the operation of Burrard Thermal and use of the Columbia River Treaty Entitlement, as it is not generated in BC, the government stacked the deck to make Site C the most attractive option. They also misled the public, the First Nations and the JRP on the estimated cost of the Project.

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8 Letter from Treaty 8 Tribal Association to Ministers Bennett & DeJong, dated December 10, 2014 at p. 4-7.
10 Importantly, the initial Site C Budget of $7.9 billion contained a contingency of $730 million so it is unclear why a further $400 million project reserve is necessary as well.
In spite of this, the Treaty 8 Nations put forward a number of supply alternatives that were not only competitive with the initial Site C budget, but cheaper, without the significant adverse impacts on the environment or the First Nations’ Treaty rights.\textsuperscript{11}

The JRP concluded that a number of supply alternatives are competitive, although in the long-term Site C would produce less expensive power. Importantly, these comments were made in the context of a $7.9 billion project with 70/30 debt/equity ratio, not the Project approved in the FID. The JRP asked BC Hydro to conduct a sensitivity analysis, which found that a 10 percent increase in the cost of the Project would, even based on BC Hydro’s own skewed analysis tip the scales in favour of alternatives, which would be cheaper by a sum of $120 - $230 million.\textsuperscript{12}

A subsequent review, performed by respected economist Robert McCullough, found that Site C may well be as much as twice as expensive as an alternative portfolio.\textsuperscript{13} We enclose a copy of that study for your reference.

One alternative that was not investigated by BC Hydro during the JRP phase was geothermal. The JRP chastised BC Hydro for not conducting any research into the geothermal potential notwithstanding BC Hydro’s own estimates that the resource may offer up to 700 MW of firm, economic power with low environmental costs.\textsuperscript{14} Subsequently, the Canadian Geothermal Energy Association produced a report, finding, \textit{inter alia}, that the potential for geothermal is greater than 700 MW, the resource has a lower unit energy cost and capital cost, produces more permanent jobs, avoids costly transmission upgrades and plants can be built on demand.\textsuperscript{15}

Finally, the JRP questioned BC Hydro’s methodology as the cost of alternatives remained constant, not accounting for technological changes which drive down the price of alternatives such as wind and solar. This issue is addressed in more detail in the UBC study, which finds an alternative portfolio to be $1.25 billion cheaper than Site C today, given that the cost of wind energy, in particular, has plummeted since 2014.\textsuperscript{16}

5. Greenhouse Gas Emissions

While it was not a focus of the JRP hearings, BC Hydro and the BC Government attempted to justify the approval of the Project based on a comment from the JRP that

\begin{itemize}
\item \textsuperscript{11} Raphals, P. \textit{Need for, Purpose of and Alternatives to the Site C Hydroelectric Project}, Abridged Version, April 2014, at p. 38-41.
\item \textsuperscript{12} Joint Review Panel Report at p.11 & 272; BC Hydro Response to JRP IR#77A, p. 1 & 12.
\item \textsuperscript{13} Mccullough R., \textit{Site C Business Case Assumptions Review}, May 2015 at p. 17.
\item \textsuperscript{14} Joint Review Panel Report at p. 324-325.
\item \textsuperscript{15} Canadian Geothermal Energy Association, \textit{Geothermal Energy: The Renewable and Cost Effective Alternative to Site C}, November 2014 at p. 5-12.
\item \textsuperscript{16} UBC Report at p. 93-94.
\end{itemize}
[Site C] “would produce a vastly smaller burden of greenhouse gases than any alternative save nuclear power.”

However, subsequent analysis from the Program for Water Governance comes to a different conclusion. That report finds that:

The Site C dam does not deliver energy and capacity at significantly lower greenhouse gas emissions than a fully optimized Alternative Portfolio put forward by BC Hydro (which includes wind energy). The difference in lifecycle GHG emissions, if a difference exists at all, is at most 1% of BC’s current emissions.

The study found that Site C would produce annual emissions of 500 to 1000kt/year of CO2 during the period of 2024-2030, which is a critical period for emissions reductions if Canada is to meet its commitments to reduce GHG emissions, whereas the alternative portfolio that was examined avoids this spike.

On a macro level, emissions in the province are currently projected to increase 39 per cent above 2014 levels by 2030, according to the Pembina Institute. The province will not meet its 2020 target to reduce emissions by 33 per cent below 2007 levels. The GHG issue is a red herring. Whether Site C is built, an alternative portfolio chosen, or the province chooses to rely on existing resources (eg. Canadian Entitlement), the impact on the province’s ability to meet its GHG targets is negligible. In contrast, had the Pacific Northwest LNG export facility gone ahead, its annual emissions would be more than 120 times the potential GHG emissions benefits of Site C, and would represent over 95% of British Columbia’s 2050 emissions reduction target set out in the Clean Energy Act.

6. Costs of Cancellation of Contracts

Unfortunately, we have not been able to review the numerous construction contracts that BC Hydro has executed for the Project as they have not been made available to us. However, the major contract for Main Civil Works provides unfettered discretion for BC Hydro to cancel and limited recourse for contractors to seek compensation, beyond work that has been completed and decommissioning costs and a 15% markup. We expect that similar contractual language is in the other contracts that BC Hydro has entered into and once we are provided with access we may provide further submissions for the Commission to consider.

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19 GHG Study at p.8-10.
21 GHG Study at p. 23.
22 Sections 17.1 and 17.2 of the Main Civil Works Contract.
Importantly, Contractors cannot make claims for “consequential damages” such as loss of profit or anticipated revenue. Thus, while the value of the contracts “awarded” may well be $4 billion, the actual value, if the Project is cancelled or suspended, will be based on actual work done, plus decommissioning costs.

7. The Public Interest – Justification for the Project

In 1983, the BCUC concluded that the Project could not be justified and 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 demonstrates, from a social benefit-cost point of view, that Site C is the best project to meet the anticipated supply deficiency.” Very little has changed in the 24 years since the BCUC issued its report.

As part of its terms of reference, the JRP was asked to opine whether the Project could be justified under the Canadian Environmental Assessment Act (“CEAA”). While a different statute, the test remains essentially the same and asks whether the significant adverse environmental effects can be justified if there is a public benefit.

In the Peace Valley Landowners decision, which challenged the federal Order in Council authorizing the Project under CEAA, Justice Manson held that:

The Joint Review Panel determined that the significant adverse effects of the Project are not justified. The Panel determined:

a) Justification must rest on an unambiguous need for the power, but that need had not been established;

b) Justification must also rest on analysis showing that financial costs are sufficiently attractive to make tolerable the substantial environmental, social and other costs, but that the financial costs of the Project had not been sufficiently established.

The implication is clear - not having found an “unambiguous need for the power”, the Project could not be justified. The purported benefits of the Project are illusory and the impact on the public purse and ratepayers if the Project is completed will be significant. Given the infringement of First Nations’ Treaty rights, the significant adverse effects on the environment and the financial burden on the current and future ratepayers of this project, the Project is not in the public interest.

24 Peace Valley Landowner Association v. Canada (Attorney General), 2015 FC 1027 at para. 34.
The issue of the cost of cancelling or delaying the Project is an important one, but must be balanced against the obvious benefits of cancellation, particularly the avoidance of a massive surplus created by the Dam that will have to be sold at a significant discount. The power is not needed now or anytime in the foreseeable future, either domestically or for export. The cost of completing the Project is uncertain. The “point of no return” is not when the Province has spent $2 billion or $3 billion, but when a decision is made to sink a further $8 - $10 billion knowing that the government never will be able to recover it from ratepayers or export it.

We trust that you find these submissions of assistance. Should you have any questions, please feel welcome to contact the writer.

Yours truly,
DEVLIN GAILUS WATSON

John W. Gailus

Email:  john@dglaw.ca
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JWG/lrl
Encls.

cc.  Clients
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May 9, 2011

Dear Ms. Yurkovich and Mr. Assimes:

Re: Site C Clean Energy Project (the “Project”) - Commentary Letter

The BC Hydro Integrated Team ("Project Team") has completed an updated project cost estimate and corresponding financial model ("Financial Model"). Acting in our role as financial advisor to BC Hydro, KPMG LLP ("KPMG") has been asked to review the Financial Model prepared by the Project Team. Specifically, BC Hydro requested our comments on the logical and arithmetic integrity of the Financial Model, as well as the reasonableness and appropriateness of the approach, methods and processes used in developing the assumptions ("Assumptions") transcribed in the Financial Model.

In this context, it is our understanding that the objective of the Financial Model (the "Financial Model Objectives") is to function as a tool to:

1. consolidate key input data with respect to capital costs;
2. calculate interest during construction;
3. assess the financial implications of constructing the Project; and
4. calculate the levelled unit energy cost for the Project.

Our comments are organized as follows:

A. Scope of Review;
B. Methodology
C. Findings; and
D. Restrictions.

This is Exhibit B referred to in the affidavit of Michael Skuydtki made before me on this 15th day of February, 2015.

A Commissioner for taking Affidavits for British Columbia
A. Scope of Review

The scope of our commentary is based on reviewing only the project documentation made available to us by the Project Team and interviewing members of the Project Team, BC Hydro, Partnerships BC and Pacific Liaison. Our review focused on the following:

1. the approach, methods and processes followed by the Project Team in developing the Assumptions contained in the financial model;
2. the transcription of Assumptions into the Financial Model; and
3. the construction of the base case Financial Model, insofar as its logical and arithmetic integrity is concerned, as an analytical tool that BC Hydro may use to achieve the Financial Model Objectives.

Our work did not include any of the following:

- assessing or verifying the commercial risks associated with the Project, nor commenting on the possibility of the financial projections contained in the Financial Model of being achieved;
- reviewing consistency of the Financial Model with externally linked files or verification of the contents and calculations of externally linked files in any way;
- considering any formula containing implicit assumptions, external references;
- reviewing the accuracy or appropriateness of visual elements (such as graphs) included within the Financial Model;
- assessing the completeness of the Assumptions or inputs used in the Financial Model;
- reviewing or testing of any sensitivity analysis of the Financial Model, including assessing the impact in the Financial Model of differing assumptions from base case; or
- providing any opinion or assurance regarding the functionality, accuracy or correctness of Microsoft Excel, the software program in which the Model was developed and operates, not the operating system that any users uses to run the Financial Model in Microsoft Excel.

The procedures we used to perform the work set out above do not constitute an audit or review made in accordance with any generally accepted auditing standards or company law or assessment of the technical feasibility or technical engineering review or compliance with applicable legislation.
B. Methodology

Our work is based on the following methodology:

- **Document Review** – reviewing project documents made available to us by the Project Team;
- **Interviews with Project Team Members** – conducting six interview sessions with Project Team Members. The interviews were used to develop an understanding of the process followed in creating the Assumptions contained in the Financial Model;
- **Review the process employed to develop the Financial Model assumptions**;
- **Review the transcription of inputs into the Financial Model** – we compared the Assumptions contained in the project documentation that was made available to us to those inputs used in the Financial Model; and
- **Verification of logical and arithmetic integrity of the Financial Model** – we reviewed the formula contained in the Financial Model for logical and arithmetic integrity.

KPMG employed BTY Group (a cost management and project management consultancy with extensive local experience) to aid in document review and Assumptions process review.

C. Findings

Our comments regarding each item in the scope of our work is addressed as follows:

1. **The approach, methods and processes followed by the Project Team in developing the Assumptions**

The Financial Model was populated from Assumptions developed by the Project Team for direct, indirect and other costs, contingencies, and reserves.

Various teams were involved in the development of these Assumptions. The teams were comprised of BC Hydro employees and external consultants selected by the Project Team based on their experience and qualifications.

The direct cost estimate was developed by the Site C Integrated Engineering Team. Upon its completion, a peer review was undertaken by BC Hydro's Generation Engineering Cost Estimating Team to verify pricing of the direct construction costs and compliance with BC Hydro's estimating practices. The peer review also served to examine the cost estimate for major scope omissions.

Other Assumptions were developed with assistance from subject-matter experts on the Integrated Project Team, BC Hydro Treasury Group, and Partnerships BC.

For additional oversight, we understand that the process followed by the Site C Project Team also included consultation with its Technical Advisory Board and Executive Project Board.
We have reviewed the Assumption development process and it shows a level of care and diligence consistent with an infrastructure project at this stage of development. Based on our review, it is our view that the Project Team has followed reasonable and appropriate processes for developing the Assumptions used in the Financial Model.

In addition, we found that the Unit Energy Cost calculations are consistent with methodologies described in the project documentation made available to us. It is our understanding that this methodology is approved by the British Columbia Utilities Commission for the evaluation of energy generation options.

2. Transcription of the Assumptions contained in the project documentation into the Financial Model

In respect of this review, our major findings are as follows:

- **Application of inflation rates** – The project documentation made available to us refers to the CPI index of 2.1% for use in the Financial Model. However, we noted in the Financial Model that two inflation rates (2.0% and 2.1%) were used throughout.

- **Reference to Source Documents** - There were some examples where inputs have been hardcoded into the financial model or embedded within formulas of the Financial Model. In some instances no source document was provided to support these hard-coded numbers. One such example is the Forecast Return on Equity contained on the RAW-FN Reserve worksheet.

- **Transposition Error** – There was one instance of a transposition error on cell C13 on Cal-UEC worksheet in the Financial Model, which was inputted as 6.986, but the project documentation made available to us contained an assumption of 6.896.

Based on our review, with the exception of the above, we believe that the Assumptions have been properly transcribed into the Financial Model.

With respect to the exceptions and findings noted, as stated above, we did not calculate the financial effect on the Financial Model as the calculation of such sensitivities is beyond the scope of our work.

3. The construction of the Financial Model, insofar as its logical and arithmetic integrity is concerned

Based on our review of the calculations in the Model, together with management responses to queries, the more substantive issues that we identified related primarily to:

- **Hard Coded Numbers** – Many hard-coded numbers have been included in the Financial Model that do not seem to impact any of the calculations. From a presentation standpoint, these numbers may be confusing to a reviewer of the Financial Model. However, were management to run financial sensitivities in the model based on changes in inputs, confusion may exist in determining which inputs are active inputs in the calculation. Changing an inactive input will not reflect appropriately in the final calculations.
Side Calculations - There were a number of side calculations that do not affect the final
calculations. From a presentation standpoint, these numbers may be confusing to a
reviewer of the Financial Model but do not appear to have an impact on the final numbers
calculated.

Labeling - In some instances the labeling contained within the Financial Model was
inconsistent with the actual calculation. For example, in the calculation of contingencies
the label is, “Last 25% of the Work Package” whereas the actual allocation of the
contingency varied from 4-23 months in length. From a presentation standpoint, this
labelling may be confusing to a reviewer of the Financial Model but does not have an
impact on the final numbers calculated.

Based on the work we have performed and taking into account the above noted findings, the
Financial Model appears to have been constructed appropriately, insofar as its logic and
arithmetic integrity is concerned.

With respect to the exceptions and findings noted, as stated above, we did not calculate the
financial effect on the Financial Model.

Restrictions

This report is addressed to BC Hydro. We will not accept responsibility to any other party to whom
the report may be shown or who may acquire a copy of the report.

Our review findings, as set out in our report, apply only to the specified version of the Financial
Model and that has been made available to us by the Project Team. We will not be under any
obligation to perform any work, take account of or comment on any intervening events or model
changes after the issue of our report in final form to BC Hydro.

Yours very truly,

[Signature]

Gary Webster
604-646-6367
REPORT OF THE JOINT REVIEW PANEL
SITE C CLEAN ENERGY PROJECT
BC HYDRO
MAY 1, 2014

REVIEW PANEL ESTABLISHED BY THE FEDERAL MINISTER OF THE ENVIRONMENT AND
THE BRITISH COLUMBIA MINISTER OF ENVIRONMENT
SUMMARY

In August 2013, the federal and provincial governments named a Joint Review Panel to examine and to hold a public hearing on BC Hydro’s proposed Site C Clean Energy Project, a third hydroelectric facility to be built on the Peace River, near Fort St. John. This is the report of the Panel’s assessment of the Project, which the governments are required to publish. The Panel was mandated to inquire into the environmental, economic, social, health, and heritage effects of the Project and their significance, to examine proposals for the mitigation of adverse effects, and to record assertions of Project effects on the Aboriginal rights and treaty rights of the affected First Nations and Métis peoples.

Any large industrial project carries with it some costs that are not captured in a narrowly economic analysis. The question is whether the benefits from the project outweigh those costs. It is in the nature of a public hearing process that the advocates for each side speak as forcefully as they can, and that there would appear to be no middle ground. The Panel’s mandate required it to weigh both sides, and to present a balance sheet, accounting for its associated recommendations, to allow elected provincial and federal governments to determine if the benefits justify the costs. The decision on whether the Project proceeds is made by elected officials, not by the Panel.

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-term increment of firm energy and capacity at a price that would benefit future generations. It would do this in a way that would produce a vastly smaller burden of greenhouse gases than any alternative save nuclear power, which B.C. has prohibited. The Project would improve the foundation for the integration of other renewable, low-carbon energy sources as the need arises. The Project would also entail a number of local and regional economic benefits, though many of these would be transfers from other parts of the province or country. Among them would be opportunities for jobs and small businesses of all kinds, including those accruing to Aboriginal people.

There are other economic considerations. The scale of the Project means that, if built on BC Hydro’s timetable, substantial financial losses would accrue for several years, accentuating the intergenerational pay-now, benefit-later effect. Energy conservation and end-user efficiencies have not been pressed as hard as possible in BC Hydro’s analyses. There are alternative sources of power available at similar or somewhat higher costs, notably geothermal power. These sources, being individually smaller than Site C, would allow supply to better follow demand, obviating most of the early-year losses of Site C. Beyond that, the policy constraints that the B.C. government has imposed on BC Hydro have made some other alternatives unavailable.

There are other costs, however, and questions of where they fall. Replacing a portion of the Peace River with an 83-kilometre reservoir would cause significant adverse effects on fish and fish habitat, and a number of birds and bats, smaller vertebrate and invertebrate species, rare plants, and sensitive ecosystems. The Project would significantly affect the current use of land and resources for traditional purposes by Aboriginal peoples, and the effect of that on Aboriginal rights and treaty rights generally will have to be weighed by governments. It would not, however, significantly affect the harvest of fish and wildlife by non-Aboriginal people. It would end agriculture on the Peace Valley bottom lands, and while that would not be significant in the context of B.C. or western Canadian agricultural production, it would highly impact the farmers who would bear the loss. The Project would inundate a number of valuable paleontological, archaeological, and historic sites. It would have modest effects on health, which could be mitigated, although the health effects of methylmercury on people who eat the reservoir fish
1. A dam located at Axis C1, 5.5 km upstream of Axis C3
2. A dam located at Axis C2, 3 km upstream of Axis C3
3. A dam located just downstream of Wilder Creek, 11.5 km upstream of Axis C3
• Cascading dams of two or more lower in height than the proposed Site C dam that would reduce the area of flooded land while maximizing development of all of the head between Peace Canyon Dam and Axis C3.
  1. A two-dam cascade with a dam at Axis C3 and an additional dam located approximately 66 km upstream
  2. A three-dam cascade with a dam at Axis C3 and two other low dams located approximately 22 km and 59 km upstream
  3. A four-dam cascade with a low dam at Axis C3 and three other low dams located approximately 18 km, 39 km, and 61 km upstream
  4. A seven-dam cascade with a dam at Axis C3 and six other dams located approximately 10 km, 23 km, 37 km, 53 km, 65 km, and 79 km upstream

The geological conditions of the area downstream of Axis C3 were found to be less favourable, as the elevation of the bedrock outcrop on the north bank of the river drops and the slopes above the bedrock comprise debris from slides and slumping of the overburden. As a result, moving the dam further downstream, within the eastern boundary of the Site C Flood Reserve, was not considered.

After completing a technical assessment, reviewing the economic feasibility and assessing the environmental effects of the alternative means, the Proponent concluded the following:

• There are no environmental factors that would eliminate an alternative;
• The relative differences in environmental effects and functionality between alternates are small; and
• The small relative differences in benefits between the alternates do not justify the greater costs.

The Proponent determined, based on the Alternates Study, that the Project is the preferred means of cost-effectively maximizing the development of the hydroelectric potential of the Site C Flood Reserve.

2.2.2 Reservoir

The Project would create an 83 km long reservoir that would be on average two to three times the width of the current river. The reservoir would have a number of clearing treatments, including some retention of vegetation.

The reservoir would be a maximum of 55 metres (m) deep at the deepest section at the earthfill dam. The normal operating range between the maximum normal reservoir level and the minimum normal reservoir level would be 1.8 m. The Proponent’s scenario analysis predicted that the daily range was expected to be 0.6 m or less 60 percent of the time, and 1.0 m or less 75 percent of the time. In exceptional circumstances such as extreme floods, the proposed reservoir could rise above the maximum normal level for short periods. The reservoir could be drawn down below the minimum normal reservoir level for unusual system requirements or system emergencies. Because the majority of the electricity generation capacity is stored in the existing Williston reservoir, BC Hydro noted that the Site C reservoir would have one of the smallest fluctuations in the BC Hydro system.
The Panel rejects, as a governing purpose, the maximization of the hydraulic potential of the Peace River.

This is not to say that Site C is unattractive. The Panel finds that BC Hydro’s proposed dam would benefit hugely from the upstream storage and regulation, providing firm, seasonally modulated power for many decades beyond its amortization period. Provided its near-term costs are affordable, it would become a substantial addition to B.C.’s very long-term supply of low-cost “Heritage Hydro.”

14.2 PROJECT BENEFITS

14.2.1 Proponent’s Assessment

The Proponent identified important economic, environmental, and social benefits to B.C. and Canada as a result of the Project. Some would come from the low cost, low greenhouse gas (GHG) electricity generation provided by the Project, and additional benefits would come from economic development activities during construction and operation, as well as improvements to local recreation and infrastructure. As a result, according to the Proponent, the Project would leave local communities and the entire province better off.

14.2.1.1 Ratepayer Benefits

BC Hydro’s customers would benefit from electricity rates that are among the most competitively priced in North America. These competitive rates result from historic investments in the Heritage hydroelectric system paid for by previous BC Hydro customers.

The Project is identified as unique in that costs decrease over time as debt is paid down and inflation reduces the relative cost of the depreciation expenses. With rate smoothing, the Project would expect to result in a small (~3 percent) increase to rates compared to alternatives for the first five years of operation, after which rates would be lower for the rest of its operating life.

BC Hydro claimed that ratepayers would also benefit from increased certainty in the cost of supply for the Project’s operating life. The majority of the Project’s revenue requirement would be established once construction was completed and the Project enters service. BC Hydro would be able to further improve cost certainty by fixing financing for 30 years at attractive rates.

By comparison, projects such as wind power were noted to have a lower operating life than the Project and would require replacement and significant rehabilitation after 30 years. Projects with fuel requirements such as gas-fired generation would also have a shorter operating life and be subject to volatility in fuel prices.

14.2.1.2 Economic Development Benefits

The Project would also provide benefits to economic development in the Northeast Development Region, the province, and the rest of Canada through spending during construction and operation. The Proponent noted that these benefits would come through increased gross domestic product (GDP), output, household income, and employment. Table 11 summarizes the benefits to economic development for the construction and operation periods.
15.4.3 Panel’s Analysis

There are a number of projects available that can add relatively large capacity at economical costs, such as Revelstoke 6 (488 MW) and turbine upgrades at Gordon M. Shrum (220 MW). Pumped storage at Mica (465 MW) can be created, though at a cost (155 GWh) in energy.

15.4.3.1 Methodological issues

The ranking of supply (and demand-moderating) alternatives is properly done through cost-benefit analysis, which has a societal, not corporate, point of view. Distortions caused by taxes and whether costs are internal or external to the organization are removed. This involves pricing all inputs and outputs and bringing them back to present value through the use of a social discount rate (SDR), which expresses society’s time preference. Proper analysis would use a (range of) SDR(s) specified by a responsible public body, followed by more detailed analyses of the better alternatives. SDRs are often in the 2 to 4 percent range.

The detailed analyses should then adjust for environmental and social costs, technology risk, ability to follow load, system integration pluses and minuses, deliverability risk, proponent’s actual cost of capital and other factors. These would be put forward as a “stack” or “portfolio” of projects that can be drawn on, in optimal order, to meet changes in demand. Only coincidentally would the proponent’s own cost of capital equal the social discount rate, as these are different concepts.

BC Hydro, abetted by BCUC, skipped the cost-benefit phase and went directly to present-valuing alternatives. It ascribed a weighted average cost of capital (WACC) of 5 percent to itself and 7 percent (down from 6 and 8 in the EIS) to independent power producers, with the difference put down to the higher cost of capital the latter must face. Yet a principal reason private power producers face higher costs of capital is that they bear most performance risks. In BC Hydro’s case, those risks are no less real but are borne by the customer or taxpayer, not BC Hydro. This is no reason to artificially reduce BC Hydro’s WACC, especially if it is to be used as a surrogate for the SDR.

Further, BC Hydro defined its WACC as based on a supposed average of 80 percent debt and 20 percent equity. The former is cheap—it is, after all, guaranteed by a triple-A entity with taxing powers—and the latter is shadow-priced by the return on equity BCUC allows to Fortis, a private competitor. But BC Hydro’s equity is largely fictional. It is only “deemed” to have equity; in fact it has deferral accounts. Between the EIS and the IRP, the definition went from 80:20 to 70:30—and the WACC declined. Such an accounting marvel should not be allowed to drive choices that would affect the B.C. economy and landscape for many decades.

BC Hydro has run these two stages together, with the result that the Panel cannot be confident that IPP alternatives vs. BC Hydro alternatives, or supply vs. demand management alternatives, are accurately valued.

Whether from a pure benefit-cost approach or a financial analysis, it is appropriate not to include sunk costs. Put another way, if the geothermal opportunity had benefitted from an extensive program of exploratory drilling that had led to the choice of a promising site, no one would have complained. BC Hydro’s sunk costs on Site C are $5/MWh, well within the error of estimates for Site C and its alternatives.

Because Site C would be built by an entity that may only be allowed to work down its deferral accounts starting in 2018, and that would need BCUC approval to earn surpluses with which to build its desired 60:40 debt:equity ratio, it is prudent not to ascribe any return to equity in BC
15.5.1 Views of Participants

A number of participants decried the constraints of the Clean Energy Act:

- Why, for example, was it permissible to produce, compress, send by pipeline, liquefy, and ship B.C. natural gas as LNG to Asia, where it would be burned, thus adding to the global GHG burden, while burning it here would at least save the enormous costs of liquefaction and transportation? What was so holy about the 7 percent limit on its domestic use—why not 8, or 10? This artificial limit was seen as especially galling in face of the Order-in-Council allowing the LNG developers to use as much gas as they wanted.
- Self-sufficiency was questioned as an objective by several participants. If a large block of power was available under the Columbia River Treaty, why could it not be counted as a Canadian source, since it was already “paid for” by the Columbia investment? If moderate amounts of capacity or energy could be purchased at rates a third of generating it, why not?
- Three discussed the implications of removing Burrard from the energy mix, especially for peaking.

15.5.2 Panel’s Analysis

Section 2 of the Clean Energy Act (CEA) of 2010 reads in part:

“(a) to achieve electricity self-sufficiency;

“(b) to take demand-side measures and to conserve energy, including the objective of the authority reducing its expected increase in demand for electricity by the year 2020 by at least 66%;

“(c) to generate at least 93% of the electricity in British Columbia from clean or renewable resources and to build the infrastructure necessary to transmit that electricity;

“(d) to use and foster the development in British Columbia of innovative technologies that support energy conservation and efficiency and the use of clean or renewable resources; …

“(f) to ensure the authority's rates remain among the most competitive of rates charged by public utilities in North America;

“(g) to reduce BC greenhouse gas emissions

(i) by 2012 and for each subsequent calendar year to at least 6% less than the level of those emissions in 2007,

(ii) by 2016 and for each subsequent calendar year to at least 18% less than the level of those emissions in 2007,

(iii) by 2020 and for each subsequent calendar year to at least 33% less than the level of those emissions in 2007,
(iv) by 2050 and for each subsequent calendar year to at least 80% less than the level of those emissions in 2007, and

(v) by such other amounts as determined under the Greenhouse Gas Reduction Targets Act;

“(h) to encourage the switching from one kind of energy source or use to another that decreases greenhouse gas emissions in British Columbia;

“(j) to reduce waste by encouraging the use of waste heat, biogas and biomass; …

“(l) to foster the development of first nation and rural communities through the use and development of clean or renewable resources;

“(m) to maximize the value, including the incremental value of the resources being clean or renewable resources, of British Columbia's generation and transmission assets for the benefit of British Columbia;

“(n) to be a net exporter of electricity from clean or renewable resources with the intention of benefiting all British Columbians and reducing greenhouse gas emissions in regions in which British Columbia trades electricity while protecting the interests of persons who receive or may receive service in British Columbia;

“(o) to achieve British Columbia's energy objectives without the use of nuclear power…”

In addition, Burrard Thermal is not to be operated (section 11), and after 2020, self-sufficiency was to be interpreted to mean BC Hydro's actual obligations as determined in its accepted load forecast plus 3,000 GWh (section 6.2(b)). Essentially all generation options outside the Heritage Hydro system, which includes Site C, are reserved for independent power producers (IPPs), ostensibly on efficiency grounds. The financial structure of BC Hydro—its “equity,” regulatory accounts, dividend requirements, water rentals, no tax obligations but externally defined grants-in-lieu—as well as the regulatory process that governs it, also operate to constrain BC Hydro’s choices or to create incentives having unforeseen consequences.

Many of these are noble objectives, perhaps especially those dealing with the reduction of greenhouse gases. Each comes with a price. In the four years since the passage of the CEA, the government has amended, clarified, or modified several of these objectives when circumstances required. For instance:

• There is an informal ban on time-of-use pricing, a well-understood method for smoothing out demand and thus avoiding very high-cost supply requirements. The Minister recently made it clear, however, that the ban does not apply to industrial loads.

• There was a danger that lengthy and duplicative proceedings by the BC Utilities Commission might delay the Project, so the Project was exempted from its normal processes by Order-in-Council.

• Likewise, the Project is apparently to be exempted from consideration by the Agricultural Land Commission.
• On the advice of a committee of deputy ministers, the government changed the definition of self-sufficiency to specify that B.C. had to be self-sufficient in an average-water year rather than a critical-water year.

• The statutory objective of building a reserve of 3,000 GWh/yr was set aside following the deputy ministers’ review of 2011. It was a very expensive objective.

• And most arrestingly of all, given the government’s commitment to GHG control, Order-in-Council 572 of July 24, 2012, allows LNG companies to use their own product for liquefaction. If the government’s hopes for this industry are realized, then section 2(g) of the CEA above is at risk, as it would undermine the efficacy of the Order-in-Council under section 35(d), which says changes to the objectives can be made by Order-in-Council so long as there is no effect on section 2(g).

Burrard Thermal is a special case. The Panel repeatedly heard from residents in the Peace region that the only reason Site C was to be built was to save the residents of the Lower Mainland from the gas-generated smog that would accompany winter inversions. BC Hydro denied this, saying that Burrard energy had already been replaced by the Clean Power Call and other IPP contracts since 2009, and that Burrard’s capacity would be replaced by Mica Units 5 and 6, all of which was factored in prior to determining Project need, and that Site C was needed to meet future demand. This ignores the fact that if Burrard were allowed to operate, perhaps only in peaking or emergency mode, some of those clean power options would have been available for the day when Site C would be called on.

Burrard is roughly the same size as Site C: 6.1 TWh/yr if operated at base load and 875 MW of capacity as against 5.1 and 1,100. Were this old plant to be used more than occasionally, it would require refurbishments estimated at $400-600 million in 2008, possibly more than a billion today. In the view of some participants at the Hearing, British Columbians are being called on to pay the $7.9 billion cost of Site C in order to displace environmental externalities from a paid-for plant in the Lower Mainland to a region that has already “suffered enough.” This view, of course, does not account for the price of gas, or the environmental costs of fracking.

15.5.2.1 Portfolio options within policy constraints

Table 19 shows a number of options for both energy and capacity.

Table 19. Energy Supply Options Within Policy Constraints

<table>
<thead>
<tr>
<th>Option</th>
<th>Energy, GWh/yr</th>
<th>Capacity, MW</th>
<th>UEC at POI, $2013/MWh</th>
</tr>
</thead>
<tbody>
<tr>
<td>Wood-based biomass</td>
<td>9,772</td>
<td>1,226</td>
<td>122-276</td>
</tr>
<tr>
<td>Biogas from biomass</td>
<td>134</td>
<td>16</td>
<td>59-154</td>
</tr>
<tr>
<td>Municipal solid waste</td>
<td>425</td>
<td>50</td>
<td>85-184</td>
</tr>
<tr>
<td>Wind, onshore</td>
<td>46,165</td>
<td>4,271</td>
<td>90-309</td>
</tr>
<tr>
<td>Combined-cycle gas turbine and co-generation</td>
<td>6,103</td>
<td>774</td>
<td>58-92</td>
</tr>
<tr>
<td>Run-of-river</td>
<td>24,543</td>
<td>1,149</td>
<td>97-493</td>
</tr>
<tr>
<td>Geothermal</td>
<td>5,992</td>
<td>780</td>
<td>91-573</td>
</tr>
</tbody>
</table>

Note: UEC at POI means Unitized Energy Cost at Point of Interconnection

Only a fraction of these options have costs close to Site C, but BC Hydro estimates in Chapter 3 of its current Integrated Resources Plan that 4 TWh of geothermal power and about 700 MW of capacity could be available within a range of $91 to $105 per MWh. This is a very large resource. It may not need to be called on until the 2030s, giving plenty of time for further
environmental costs but gain little, even though they will seek job training, guaranteed jobs, and financial benefits. They fear loss of access to graves and cultural sites, loss of hunting opportunities, loss of parts of their trap lines, loss of preferred species to fish, and poisoning from mercury in fish. All Aboriginal groups without exception asserted they will be directly and adversely affected by the Project. All but two Aboriginal groups opposed the Project. Of the remaining two, one favoured the Project and one was ambivalent.

A case has recently been made that large amounts of power may be necessary for new liquefied natural gas (LNG) and mining projects. However, large LNG plants and pipelines are likely to be powered by natural gas directly. Moreover, if projects proceed as rapidly as the government expects, power will be required before Site C would be operational.

Burning a small fraction of that methane for power in B.C. would have several advantages. Capacity could be added relatively quickly, in smaller increments as demand develops, near load center so as to minimize losses, and with a lower overall contribution to the global greenhouse gas burden than if LNG were exported. The LNG developers have been promised a free hand to burn their gas here for their own purposes, but BC Hydro has been denied the same privilege.

Someday, a growing B.C. economy will need another 5 TWh of energy. The question is when. For a number of reasons set out in the text, the Panel cannot conclude that the power of Site C is needed on the schedule presented.

A second question is what alternatives may be available when that day comes. One major alternative should have been fully characterized many years ago. In 1983, the BC Utilities Commission advised BC Hydro to explore the promising geothermal resources in the Coast Range, near the load center. Little has been done. Since then, new geothermal resources have been discovered in the sedimentary rocks of northeast BC. BC Hydro now says 700 MW of firm power via geothermal resources may be available at competitive prices. They are, however, forbidden by policy to develop it. Development is reserved for independent power producers, none of whom have bid geothermal projects into the recent calls for proposals.

There are a number of other renewable alternatives available at costs comparable to Site C, but these have been only roughly costed in the Environmental Impact Statement. As a matter of public policy, BC Hydro is not allowed to develop them and so has not invested much in exploration, research, and engineering. The consequence is that there is less confidence in the costs of the alternatives than with Site C; likewise, the understanding of the environmental costs of alternatives is necessarily generic.

The Panel was asked to present evidence that could lead to the justification of the environmental, social, economic, health, and heritage costs of the Project. Those costs are large, and governments in the past have been cautious about licensing projects with significant adverse residual effects. Justification must rest on an unambiguous need for the power, and analyses showing its financial costs being sufficiently attractive as to make tolerable the bearing of substantial environmental, social, and other costs.

Site C, after an initial burst of expenditure, would lock in low rates for many decades, and would produce fewer greenhouse gas emissions per unit of energy than any source save nuclear. These advantages must be set against permanent damages to nature, the interests of First Nations, and to the specific local interests described in this report.
APPENDIX 1 LIST OF PANEL’S CONCLUSIONS AND RECOMMENDATIONS

The Panel was required to conduct an assessment of the Project in a manner consistent with the requirements of the Terms of Reference. The Panel has identified those conclusions and recommendations that relate to the environmental effects to be taken into account under section 5 of CEAA 2012. See endnote.

The following provides the Panel’s conclusions on the significance of the effects of the Project and potential impacts on asserted or established Aboriginal rights or treaty rights in the area of the Project and its recommendations.

A number of the Panel’s recommendations are addressed to governments rather than BC Hydro and are not to be interpreted as conditions to be attached to Project approvals. Rather, they are put forward to assist governments and proponents with assessments of this and future projects.

The Panel has reached conclusions and makes recommendations as follows.

Alternative Means of Carrying out the Project

**The Panel concludes** that the Proponent’s assessment of alternative means of carrying out the Project is appropriate.

Aquatic Environment

**The Panel concludes** that the Project would make small changes to the hydrology of the Peace River, and such changes would be attenuated by the time the flows reach Peace River, Alberta.4

**RECOMMENDATION 1**
With respect to minimum flow, the Panel recommends that, if the Project proceeds, a minimum release of 390 cubic metres per second from the Site C dam be a condition of approval.

**The Panel concludes** that there may be some risk to existing infrastructure in Alberta from low flows and that this risk has not been assessed.2

**RECOMMENDATION 2**
With respect to potential transboundary effects on hydrology, the Panel recommends that, if the Project proceeds, the Proponent must consult with the Province of Alberta and jointly develop an adaptive management plan to manage risks to infrastructure downstream caused by low flows during reservoir filling and operation. The plan should include:

- Assessment of risks to infrastructure;
- Monitoring of flows;
- Identification of problems; and
- Necessary mitigation through flow regulation or adjustment to Alberta infrastructure to minimize impacts.
The Panel agrees with BC Hydro’s assessment that there would not be a change in ice thickness, break-up time, or freeze-up water levels with the Project, downstream at Shaftsbury near Peace River Alberta.²

The Panel agrees with BC Hydro’s study results that indicate the downstream extent of Site C’s influence on the ice regime would be approximately 550 kilometres downstream of the dam site at Carcajou.²

The Panel concludes that the Project would result in negligible changes to fluvial geomorphology and sediment transport.⁴

The Panel concludes the Project would result in localized adverse effects on groundwater that would not be significant.⁴

The Panel concludes that there would be a risk of acid generation and metal leaching from construction activities and reservoir creation. However, if the Panel’s recommendation is implemented, the effects would not be significant.⁴

**RECOMMENDATION 3**
To address the potential risk of acid rock drainage and metal leaching from the Project activities, the Panel recommends that, if the Project proceeds, BC Hydro must consult with Environment Canada, Natural Resources Canada, and Ministries of Environment and Forests, Lands and Natural Resource Operations to design a program to monitor water quality and procedures to mitigate related issues that may arise and to implement the program if necessary.

The Panel concludes there would be no effects from the Project on any aspect of the environment in the Peace Athabasca Delta, and a cumulative effects assessment on the PAD is not required.²

**Fish and Fish Habitat**

The Panel agrees with BC Hydro that the Project would cause significant adverse effects on fish and fish habitat.¹

The Panel concludes that the construction of the Project would result in significant adverse cumulative effects on fish.¹

**Vegetation and Ecological Communities**

The Panel agrees with BC Hydro that the effects of the Project on at-risk and sensitive ecological communities would be significant.⁴

**RECOMMENDATION 4**
In order to improve the accuracy and reliability of the baseline mapping and habitat interpretations and to inform mitigation measures and compensation, the Panel recommends that, three month before any activity affecting these habitats, BC Hydro must review its modeling and complete the field work needed to improve identification of rare and sensitive communities and aid in delineation of habitats that may require extra care in the development and operation of the Project.

The Panel disagrees with BC Hydro and concludes that the Project would have a significant adverse effect on wetlands, in particular valley bottom wetlands.¹
RECOMMENDATION 5
The Panel recommends that, if the Project proceeds, BC Hydro must conduct an assessment of wetland functions lost to the Project that are important to migratory bird and species at risk (wildlife and plants). The Panel also recommends BC Hydro monitor construction and operation activities that could cause changes in wetland functions. The results must inform the development of the mitigation measures to ensure wetland functions at least meet federal and provincial regulatory and policy requirements. BC Hydro must consult with Environment Canada and the Ministry of Forests, Lands and Natural Resource Operations on the duration and frequency of monitoring in relation to migratory birds, species at risk and other wildlife using wetlands.

RECOMMENDATION 6
The Panel recommends that, if the Project proceeds, BC Hydro must complete a Wetland Compensation Plan that includes the results of the functions assessment, surveys, and monitoring program identified above. In developing the Wetland Compensation Plan, BC Hydro must:

a) Discuss migratory birds and species at risk with Environment Canada, the Ministry of Forests, Lands and Natural Resource Operations and Aboriginal groups;
b) Ensure that the Wetland Compensation Plan achieves a full replacement of the wetlands lost in terms of functions and compensates in terms of area;
c) Consult with interested and implicated agencies on the draft Wetland Compensation Plan to ensure effects on Crown land are considered; and
d) Submit the final Wetland Compensation Plan to Environment Canada and other relevant authorities no later than three months prior to any activity affecting the wetlands.

The Panel agrees with BC Hydro that the Project would cause significant adverse effects on rare plants.4

RECOMMENDATION 7
The Panel recommends that, if the Project proceeds, BC Hydro must undertake surveys no later than three months prior to any activity affecting rare plants to determine whether the rare plant species potentially facing extirpation are found elsewhere in the region. If the plants cannot be found elsewhere, appropriate conservation methods to ensure the viability of the rare plant species must be put in place, such as ensuring that seeds are kept or relocation of plant communities is attempted.

Given the lack of assessment by BC Hydro, the Panel cannot conclude on effects of the Project on plants of interest to Aboriginal groups.3

RECOMMENDATION 8
The Panel recommends that, if the Project proceeds, BC Hydro must conduct a comprehensive assessment of effects on traditional plants in collaboration with Aboriginal groups, three months before any activity affecting the plants, to identify areas where plants of interest may be. The results should be used to improve the measures needed to fully mitigate any adverse effects of the Project on plants traditionally used by Aboriginal groups.

RECOMMENDATION 9
The Panel recommends that, if the Project proceeds, BC Hydro be prohibited from using herbicides and pesticides near locations of plants of importance to Aboriginal groups.
The Panel agrees with BC Hydro that cumulative effects on vegetation and ecological communities would be significant.\(^1,3,4\)

**Wildlife Resources**

The Panel concludes that the Project would likely cause significant adverse effects to the following species that may see their status of protection elevated. These species are: Nelson’s sparrow; yellow rail; eastern phoebe; Le Conte’s sparrow; old world swallowtail, *pikei* subspecies; Alberta arctic; striped hairstreak; great spangled fritillary, *pseudo Carpenteri* subspecies; coral hairstreak, *titus* subspecies; common wood-nymph, *nephele* subspecies; Uhler’s arctic; tawny crescent; arctic blue, *lacustris* subspecies; Aphrodite fritillary, *manitoba* subspecies; sharp-tailed grouse, *jamesi* subspecies and Baltimore oriole.\(^1,3,4\)

The Panel disagrees with BC Hydro and concludes that the Project would likely cause significant adverse effects to the western toad.\(^4\)

The Panel disagrees with BC Hydro and concludes that the Project would likely cause significant adverse effects to broad-winged hawk, short-eared owl, eastern red bat, little brown *myotis* and northern *myotis*.\(^4\)

The Panel agrees with BC Hydro that the Project would not likely cause significant adverse effects on fisher and grizzly bear.\(^3\)

The Panel concludes that the effects on caribou as a result of the Project would not be significant.\(^3\)

**RECOMMENDATION 10**

The Panel recommends that if the Project proceeds, the Proponent must conduct field work to verify the modeled results for surveyed species at risk and determine, with specificity and by ecosystem, the habitat lost or fragmented for those species. The Proponent shall use these data to inform final project design and to develop additional mitigation measures, as needed, in consultation with appropriate authorities.

**RECOMMENDATION 11**

The Panel recommends that if the Project proceeds, the Proponent must track updates to the status of listed species identified by the Province, the Committee on the Status of Endangered Wildlife in Canada, and the *Species at Risk Act*. Should the status of a listed species change during the course of the Project, the Proponent must work with Environment Canada and the Ministry of Forests, Lands and Natural Resource Operations to mitigate effects of the Project on the affected species.

**RECOMMENDATION 12**

The Panel recommends that Environment Canada complete a recovery strategy, in a timely manner, for the species listed under schedule 1 of the *Species at Risk Act* for which recovery strategies have not yet been developed (Canada warbler, olive-sided flycatcher and common nighthawk, rusty blackbird and short-eared owl and western toad).

The Panel concludes that the Project would likely cause significant adverse effects to migratory birds relying on valley bottom habitat during their life cycle and these losses would be permanent and cannot be mitigated.\(^1\)
RECOMMENDATION 13
The Panel recommends that, should the Project proceed, BC Hydro must develop a monitoring and mitigation program in consultation with Environment Canada to avoid the loss of active migratory bird nests in the reservoir area and downstream of the dam.

RECOMMENDATION 14
The Panel recommends that, should the Project proceed, BC Hydro must develop mitigation measures specific to migratory bird species in the Project area that address the changes in aquatic and riparian-related food resources and other habitat features associated with the change from a fluvial to a reservoir system, in consultation with Environment Canada.

RECOMMENDATION 15
The Panel recommends that, should the Project proceed, BC Hydro must conduct a risk assessment for bird collisions under the current transmission line design. BC Hydro must determine if additional mitigation measures (e.g. line marking and diversions) could be implemented to reduce the risk, in consultation with Environment Canada.

RECOMMENDATION 16
The Panel recommends that, should the Project proceed, BC Hydro be required to develop a Compensation Plan for non-wetland migratory birds in consultation with Environment Canada, and implement the plan to address significant adverse effects on Canada warbler, Cape May warbler, and bay-breasted warbler. The plan must be submitted to Environment Canada three months prior to any activity affecting the habitat.

The Panel agrees with BC Hydro that the Project would not likely cause significant adverse effects on moose, elk, white-tailed deer and mule deer.¹

RECOMMENDATION 17
The Panel recommends that, if the Project proceeds, the Proponent must, in collaboration with the Province, determine whether additional lands owned by BC Hydro or Crown Lands could be maintained as winter range for ungulates.

RECOMMENDATION 18
The Panel recommends that, if the Project proceeds, the Ministry of Forests, Lands and Natural Resource Operations must conduct bi-annual ungulate surveys in Wildlife Management Units overlapping with the LAA during Project construction and for a period of 5 years after. This information must be provided to the Proponent to confirm the effects of the Project and used by the Ministry to determine if mitigation is required (for direct or indirect effects).

The Panel concludes that the wildlife species that would experience significant effects as a result of the Project would also experience significant cumulative effects.¹,³,⁴

The Panel concludes that given that fisher are blue-listed and likely already impacted by human pressures, the Project effects in combination with past, existing and future projects may cause significant cumulative effects.³

The Panel concludes that the Project would not likely cause significant cumulative effects on ungulates.³

Current Use of Lands and Resources for Traditional Purposes

The Panel disagrees with BC Hydro and concludes that the Project would likely cause a significant adverse effect on fishing opportunities and practices for the First Nations represented
by Treaty 8 Tribal Association, Saulteau First Nations, and Blueberry River First Nations, and that these effects cannot be mitigated.³

**The Panel disagrees** with BC Hydro and concludes that the Project would likely cause a significant adverse effect on hunting and non-tenured trapping for the First Nations represented by Treaty 8 Tribal Association and Saulteau First Nations, and that these effects cannot be mitigated.³

**The Panel concludes** that the Project would likely cause a significant adverse effect on other traditional uses of the land for the First Nations represented by Treaty 8 Tribal Association, Saulteau First Nations, and Blueberry River First Nations, and that some of these effects cannot be mitigated.³

**The Panel concludes** that the Project would likely cause significant adverse cumulative effects on current use of lands and resources for traditional purposes.³

**RECOMMENDATION 19**
The Panel recommends that, if the Project does not proceed, the Province, after consultation with affected local parties, remove the flood reserve in a manner that preserves the agricultural, wildlife and heritage values of the Peace River valley.

**RECOMMENDATION 20**
The Panel recommends that the Province set aside the hunting, fishing and trapping rights in the Peace Moberly Tract for people holding Section 35 rights under the *Constitution Act, 1982*. The Panel also recommends that the Province and affected First Nations enter discussions on the Area of Critical Community Interest with a view to the harmonious accommodation of all interests in this land.

**Other Harvest of Fish and Wildlife Resources**

**The Panel agrees** with BC Hydro that the effects of the Project on harvest of fish would not be significant.⁵

**The Panel agrees** with BC Hydro that the effects of the Project on harvest of wildlife would not be significant.⁵

**The Panel concludes** that, if the Project proceeds, some tenured trappers and outfitters would be adversely affected by the construction and operation activities of the Project. If the Panel’s recommendation is implemented, this effect would not be significant.³,⁵

**RECOMMENDATION 21**
The Panel recommends that, if the Project proceeds, fair compensation should be offered to affected tenured trappers and outfitters for long term losses.

**The Panel concludes** that more information is needed to assess the effects of the Project on harvest of wildlife resulting from an influx of workers from outside the Peace region and the opening of the territory by the construction of new access roads and the improvement of the road system.³,⁵

**RECOMMENDATION 22**
The Panel recommends that, if the Project proceeds, BC Hydro must determine, in collaboration with applicable agencies, stakeholders and Aboriginal groups, what enforceable restrictions can be put in place with respect to the Project access road, and
which existing roads in the vicinity and new roads built during construction should be decommissioned.

The Panel agrees with BC Hydro that the cumulative effects on harvest of fish and wildlife would not be significant.\textsuperscript{3,5}

**Agriculture**

The Panel concludes that the permanent loss of the agricultural production of the Peace River valley bottomlands included in the local assessment area of the Project is not, by itself and in the context of B.C. or western Canadian agricultural production, significant. The Panel further concludes that this loss would be highly significant to the farmers who would bear the loss, and that financial compensation would not make up for the loss of a highly valued place and way of life.\textsuperscript{5}

The Panel agrees with BC Hydro that the Project would not cause cumulative effects on agriculture.\textsuperscript{5}

**Effects on Other Resources Industries**

The Panel concludes that the Project would have negligible effects on the regional oil and gas, forest, and mineral and aggregate industries.\textsuperscript{5}

**Transportation**

The Panel concludes that the traffic at some places on Highway 97 is already dangerous, and during the period of construction, the Project would add to that, but there would be no residual effects after the construction period. If the Panel's recommendations are implemented, this effect would not be significant during construction.

**RECOMMENDATION 23**

As proposed by BC Hydro, the Panel recommends that, if the Project proceeds, it must establish a current baseline of fog occurrences at Taylor Bridge and its approaches in Taylor, as well as follow-up monitoring during the first years of operation to evaluate the magnitude of any changes as a result of the Project.

**RECOMMENDATION 24**

The Panel recommends that, if the Project proceeds, BC Hydro must conduct monitoring of the Level of Service and road safety. Monitoring and a follow-up program shall focus on the following locations:

- Highway 97 at Old Fort Road in Fort St. John,
- Highway 97 at 100th Street in Fort St. John,
- Highway 97 at 85th Avenue in Fort St. John,
- Canyon Drive in Hudson’s Hope,
- Beattie Drive in Hudson’s Hope,
- Clarke Avenue in Hudson’s Hope.

**RECOMMENDATION 25**

The Panel recommends that, if the Project proceeds, BC Hydro’s Traffic Monitoring and Management Plan and associated work schedules must be prepared, subject to safety considerations, to minimize delays and nuisance caused by the realignment of Highway 29, particularly during peak visitor periods.
Air Navigation

The Panel concludes that the Project would not result in significant adverse effects on air navigation.4

Water Navigation

The Panel concludes that the Project would have adverse effects on navigation use of the Peace River but that they would not be significant because the river would still be navigable above and below the dam site. The Panel further concludes that the loss would be significant for the small number of people who traverse the dam site.4

The Panel concludes that there would be no cumulative effects on navigation of the Peace River if the Project proceeds.4

Outdoor Recreation and Tourism

The Panel concludes that the construction period would have an adverse effect on outdoor recreation activities associated with the Peace River, but this effect would not be significant.5

The Panel concludes that the cumulative effects on outdoor recreation and tourism would not be significant.5

Population and Demographics

The Panel concludes that population effects would be primarily limited to the construction phase of the Project, when modest increments to the local and City population would occur. Because most of these effects would be limited to the construction phase, the Panel concludes these effects would not be significant.

Housing

Considering the mitigation commitments presented by BC Hydro to address housing issues related to the Project, the Panel is satisfied that there would not be significant adverse effects on housing solely as a result of the Project.

RECOMMENDATION 26
The Panel recommends, regardless of whether or not the Project proceeds, that the Province give sympathetic attention to an extension of Fort St. John’s municipal boundaries so that contiguous urbanizing areas, plus a reserve, are brought within the planning, service, and taxation ambit of the City’s government.

Community Infrastructure and Services

The Panel concludes that the general stress on community infrastructure and services caused by the Project could be managed with sufficient resources. The Panel is confident that mitigation in the form of additional resources would be provided by BC Hydro and appropriately managed by the communities (including municipalities) such that effects would not be significant.

RECOMMENDATION 27
The Panel recommends that, should the Project proceed, BC Hydro must include in its agreement with the City of Fort St. John expenses for Project-related costs of child and family welfare services.
Employment, Labour Markets and Local Residents

The Panel concludes that the Project would further tighten a labour market where the unemployment rate is only 3.6 percent, and that it is in everyone’s interest to ensure that local Aboriginal workers are as well-equipped as possible to compete in that market.

The Panel further concludes that, with the implementation of the proposed mitigation measures, there should be no significant adverse effects on the labour market.

RECOMMENDATION 28
The Panel recommends that, if the Project proceeds, BC Hydro must work with training institutions to focus on employment in indirect and induced sectors for Aboriginal workers, as these jobs are likely to be longer lived than those related strictly to construction.

Local Government Revenue

The Panel concludes that revenues to be received from existing sources, together with payments contemplated in negotiations between the Proponent and local governments, would generally be sufficient to maintain current service quality levels. Several such agreements are already in place. No significant adverse effects are foreseen, nor are cumulative effects.

The Panel further concludes that the negotiations of Impact and Benefit Agreements with local affected Aboriginal groups would generally be sufficient to maintain current service quality levels both on- and off-reserve.

Regional Economic Development

The Panel concludes that there would be excellent opportunities for new and existing jobs and businesses during the construction phase.

Human Health

The Panel concludes that, if the Project proceeds, there is a potential for health effects from a degradation of air quality in the region of Fort St. John, Taylor, Hudson’s Hope and for Aboriginal groups using areas close to the construction activities of clearing and burning, the construction of access roads and the realignment of Highway 29. The predicted results would have to be confirmed through monitoring and the mitigation measures adjusted if needed. These effects could be overcome with proper mitigation. If the Panel’s recommendation is implemented, there would be no residual effects.

RECOMMENDATION 29
The Panel recommends that, if the Project proceeds, BC Hydro must:

- Add monitoring at sensitive receptor group locations to the monitoring plan for dust and smoke;
- Prolong the monitoring proposed for the construction period into the first two years of operation for particulate matter and dustfall. In case of exceedances, appropriate mitigation measures must be implemented;
- Identify places of high Aboriginal group use and develop mitigation measures should adverse effects be predicted at those locations; and
- Ensure procedures are developed to warn and protect sensitive populations in cases of exceedance.
The Panel disagrees with BC Hydro that there would be no effects on individual wells. There would be a risk of exceedances of drinking water quality guidelines for a number of wells. If the Panel’s recommendation is implemented, there would no residual effects.5

RECOMMENDATION 30
The Panel recommends that, if the Project proceeds, BC Hydro be required to monitor potentially affected wells, starting as soon as Project approval is received. Monitoring must be done twice a year for 10 years. If any changes are observed the owners must be informed. If any functionality problems such as poor water quality or low yield result from the Project, BC Hydro must work with the well owner(s) to provide an alternate source of potable water.

For the City of Fort St. John’s and the District of Taylor’s water supply wells, the Panel agrees with BC Hydro that exceedances of drinking water quality guidelines are not anticipated.5

The Panel concludes that there are predicted exceedances of the BC Oil and Gas Commission guidelines and changes in sound levels at some receptors - above 5 dBA at one residence and above 10 dBA at worker camps. If the Panel’s recommendation is implemented, there would be no residual effects.5

RECOMMENDATION 31
The Panel recommends that, if the Project proceeds, BC Hydro must:

- Design a work and noise management schedule that allows an uninterrupted eight hour sleep schedule for workers; and
- Manage Project noise to provide quiet enjoyment to residents, even if it means temporary relocation.

The Panel agrees with BC Hydro’s conclusion that no adverse health effects associated with exposure to electric and magnetic fields are expected.3

RECOMMENDATION 32
The Panel recommends that, if the Project proceeds, BC Hydro must measure post-construction electric and magnetic field levels at the right-of-way edge where habitation sites exist and communicate the results to occupants. If monitoring determines an exceedance of the International Commission on Non-Ionizing Radiation Protection guidelines (4.2 kV/m) at a habitation site, BC Hydro must provide the necessary resources for relocation.

Regarding fish consumption data used by BC Hydro in the Mercury Human Health Risk Assessment, the Panel concludes there are no reliable data available at this point.3,5

RECOMMENDATION 33
The Panel recommends that, if the Project proceeds, BC Hydro must work cooperatively to obtain site-specific data from Aboriginal groups. The dietary information to be collected from potentially impacted groups should include:

- Species and size of fish caught for consumption;
- Location where fish are caught for consumption;
- Consumption of fish by age group;
- Parts of fish consumed;
- Fish preparation methods;
• Fish meal sizes by age group;
• Fish meal frequency; and
• Other relevant consumption information (e.g. events where consumption is higher over a short period of time such as a camping event).

The Panel concludes that only monitoring of the fish in the reservoir and the consumption habits of the people would provide an adequate base for the development of effective mitigation measures for methylmercury.\(^3,5\)

**RECOMMENDATION 34**
The Panel recommends that, if the Project proceeds, the monitoring program must require the collaboration of Health Canada and include:

• Involving local Aboriginal communities and the First Nations Health Authority in the design, implementation, management and interpretation and communication of results from the methylmercury monitoring program for fish;
• Collecting representative data through collaboration with Aboriginal communities to enable meaningful sampling of the appropriate fish species and fish size in areas where groups harvest fish. The spatial extent of the sampling program should include tributaries used by Aboriginal groups; and
• Working with all levels of government to communicate information to Aboriginal groups and others regarding potential fish consumption advisories and other health-related bulletins or information as may be necessary.

**RECOMMENDATION 35**
The Panel recommends that, in the event that Health Canada determines a consumption advisory is needed, the Chief Medical Officer of Northern Health must be notified by Health Canada. The advisory should be designed and implemented in accordance with federal and provincial procedures for issuing fish consumption advisories. It should be issued using good practice including:

• Culturally appropriate communications to Aboriginal groups;
• Mechanisms to receive and respond to inquiries from local communities in regards to the advisories; and
• A collaborative monitoring process with Aboriginal and other communities.

**RECOMMENDATION 36**
The Panel recommends that, if the Project proceeds, effective communication with Aboriginal communities and other stakeholders is required by Health Canada whether an advisory is needed or not. This should include:

• Communication of the results of the Mercury Human Health Risk Assessment, including guidance for people consuming more than one species of fish and how they can continue to eat multiple species without exceeding the provisional tolerable daily intake for methylmercury; and
• Communication of consumption limits in grams per week rather than servings per week. Further guidance should be provided as to what a gram of fish is equivalent to in order to make the communications more user-friendly.
The Panel concludes that some homes close to the construction of the dam and in Hudson’s Hope shoreline protection activity area would experience an increase in noise combined with a degradation of the ambient air quality.\textsuperscript{3,5}

**RECOMMENDATION 37**
The Panel recommends that, if the Project proceeds, where monitoring indicates that homeowners are experiencing serious nuisance as a result of the Project, BC Hydro be required to mitigate those effects, up to and including relocation if necessary.

The Panel agrees with the Proponent that there would be no significant adverse effects on human health taking into account the mitigation measures proposed by the Proponent and the Panel recommendations.\textsuperscript{3,5}

Because of the uncertainty in the assessment, the Panel concludes that there is no need at present to do a cumulative effects assessment on health indicators but that one may be required once effects are confirmed through monitoring.\textsuperscript{3,5}

**Heritage Resources**

The Panel concludes that residual adverse effects on physical heritage resources caused by the Project would be adverse and significant.\textsuperscript{3,5}

**RECOMMENDATION 38**
The Panel recommends that, if the Project proceeds, BC Hydro must monitor reservoir erosion during occurrences of low reservoir levels and investigate, according to the requirements of the Archaeology Branch of the Ministry of Forests, Lands and Natural Resource Operations, any potentially new-found sites and carry out emergency salvage.

**RECOMMENDATION 39**
The Panel recommends that, if the Project proceeds, BC Hydro must conduct monitoring of shoreline erosion downstream (for approximately 2 km) as part of its chance find procedures to determine if physical heritage resources are affected. The Panel recommends that BC Hydro undertake this monitoring for any spills from the Project reservoir, for a period of 2 years.

**RECOMMENDATION 40**
The Panel recommends, if the Project proceeds, that BC Hydro must continue its collaboration with First Nations and the Métis Nation British Columbia, for the days committed on ground truthing for the identification of any burial sites that the Project may disturb.

**RECOMMENDATION 41**
The Panel recommends that, if the Project proceeds, BC Hydro must provide sufficient funds to local accredited facilities in close proximity to the Project to curate and display the recovered resources. The Panel further recommends that these funds be provided only to facilities that agree to work with Aboriginal groups on the display and curation of those artifacts.

The Panel concludes that the cumulative adverse effects on heritage resources would be significant.\textsuperscript{3,5}

The Panel concludes that there would be significant adverse effects of the Project on cultural heritage resources for both Aboriginal and non-Aboriginal people.\textsuperscript{3,5}
The Panel concludes that the effect of the Project on visual resources would be a significant adverse effect.\(^3,5\)

**GHG Emissions**

The Panel concludes that the Project would produce more power per gram of CO\(_{2e}\) than any alternative (non-nuclear) over its lifetime.\(^2\)

The Panel agrees with BC Hydro that the Project’s effects on greenhouse gases would not be significant.\(^2\)

The Panel agrees with BC Hydro that the contribution of the Project to the provincial, national and global problem would not be significant.\(^2\)

**Effects of the Environment on the Project**

The Panel concludes that the design of the Project adequately accounts for possible adverse effects of the environment on the Project.

**Accidents and Malfunctions**

The Panel concludes that the effects of the Project from minor accidents and malfunctions are not likely to be significant and that BC Hydro has demonstrated appropriate diligence in its analysis and proposed mitigation.

The Panel concludes that a Site C dam breach would result in significant adverse effects, but that the probability of failure occurring is remote. The Panel further concludes that any effects of a cascading dam failure would result in significant cumulative effects, but that the probability of cascading failure is extremely remote.

**RECOMMENDATION 42**

The Panel recommends that, if the Project proceeds, BC Hydro be required to conduct an assessment of the impacts of a multiple cascading dam breach and share the results of that study with the Government of Alberta and the authorities of the towns that would be affected. The Panel recommends that BC Hydro consult with Alberta and emergency management officials in both provinces on communication and contingency plans to address the potential occurrence of a multiple cascading dam breach.

**Cumulative Effects Assessment**

The Panel concludes that, whether the Project proceeds or not, there is a need for a government-led regional environmental assessment including a baseline study and the establishment of environmental thresholds for use in evaluating the effects of multiple, projects in a rapidly developing region.

**RECOMMENDATION 43**

Given the rapid developments foreseen for northeast B.C., Ministers may wish to consider commissioning a regional baseline study and environmental assessment as a public good and a basis for planning and regulating all activities requiring review. Such a study would greatly assist future proponents in all sectors, notably oil and gas, forestry, mining and energy production.
Because of the importance of cumulative effects assessment, the Panel concludes that there is a need to improve and standardize cumulative effects assessment methods.

**RECOMMENDATION 44**
Whether the Project proceeds or not, the Panel recommends that the Canadian Environmental Assessment Agency undertake, on an urgent basis, an update of its guidance on cumulative effects assessment, taking into account the views of the provinces.

**Capacity of Renewable Resources**

The Panel concludes that because of the significant adverse effects identified on some renewable resource valued components in the long-term, if the Project is to proceed, there would be diminished biodiversity and reduced capacity of renewable resources.

**Environmental Management Plans, Follow-up and Monitoring**

Subject to the recommendation below, the Panel is satisfied with the Proponent’s environmental management, including its mitigation measures, monitoring programs, and follow-up programs.

**RECOMMENDATION 45**
The Panel recommends that, if the Project is to proceed, all recommendations of the Panel directed to BC Hydro and mitigation measures proposed by BC Hydro become conditions of Project approval.

**Purpose of the Proposal**

The Panel rejects, as a governing purpose, the maximization of the hydraulic potential of the Peace River.

**Project Benefits**

The Panel concludes that the Project must rest on its main claims - that it would supply electricity that B.C. customers need and would pay for, at a lower combination of cash and external costs than any alternative - and not on regional economic benefits.

**Project Costs**

The Panel cannot conclude on the likely accuracy of Project cost estimates because it does not have the information, time, or resources. This affects all further calculations of unit costs, revenue requirements, and rates.

**RECOMMENDATION 46**
If it is decided that the Project should proceed, a first step should be the referral of Project costs and hence unit energy costs and revenue requirements to the BC Utilities Commission for detailed examination.

**Demand**

The Panel concludes that BC Hydro’s forecasting techniques are sound, but uncertainties necessarily proliferate in long-term forecasts.
The Panel concludes that it is unlikely that the transmission and liquefaction energy requirements of the new liquefied natural gas industry will be satisfied by any source except natural gas itself, and thus that BC Hydro’s Integrated Resource Plan sensitivity scenario of “Low Liquefied Natural Gas” forecast is most likely correct.

The Panel concludes that, basing a $7.9 billion Project on a 20-year demand forecast without an explicit 20-year scenario of prices is not good practice. Electricity prices will strongly affect demand, including Liquefied Natural Gas facility demand.

**RECOMMENDATION 47**

The Panel recommends that BC Hydro construct a reasonable long-term pricing scenario for electricity and its substitutes and update the associated load forecast, including Liquefied Natural Gas demand, and that this be exposed for public and Commission comment in a BC Utilities Commission hearing, before construction begins.

**Demand Moderation**

The Panel concludes that the demand-side management yield ought to at least keep up with the growth in gross demand, and therefore the potential savings from 2026 to 2033 may be understated.

Using BC Hydro’s price elasticity of demand of -0.57, accepting BC Hydro’s forecast of gross demand, and positing a real price increase of 50 percent from 2014 to 2033, the Panel concludes that net demand in 2033 is likely to be about 65 terawatt hours.

The Panel concludes that demand management does not appear to command the same degree of analytic effort as does new supply.

**Supply: Energy and Capacity**

The Panel concludes that methodological problems in the weighing and comparison of alternatives render unitized energy costs only generally reliable as a guide to investment. The Panel is more confident about the ranking of BC Hydro’s projects, or independent power producers’ projects, or demand side management projects considered as separate lists. Uncosted attributes such as the ability to follow load, geographical diversity, or the ability to assist with the integration of intermittent sources need more analytical attention.

The Panel concludes that a number of supply alternatives are competitive with Site C on a standard financial analysis, although in the long term, Site C would produce less expensive power than any alternative.

The Panel concludes that relying on exports to absorb surplus production would likely be very expensive.

**Research**

The Panel concludes that a failure to pursue research over the last 30 years into B.C.’s geothermal resources has left BC Hydro without information about a resource that BC Hydro thinks may offer up to 700 megawatts of firm, economic power with low environmental costs.

The Panel concludes that analytic efforts to quantify the potential benefits of geographic diversity and climate-induced changes to hydrology could allow a better characterization of important resources.
RECOMMENDATION 48
The Panel recommends, regardless of the decision taken on Site C, that BC Hydro establish a research and development budget for the resource and engineering characterization of geographically diverse renewable resources, conservation techniques, the optimal integration of intermittent and firm sources, and climate-induced changes to hydrology, and that an appropriate allowance in its revenue requirements be approved by the BC Utilities Commission.

Policy Constraints on Supply

The Panel concludes that, under the Low Liquefied Natural Gas case, available resources could provide adequate energy and capacity until at least 2028.

Panel’s Overall Analysis on Need for the Project

The Panel concludes that B.C. will need new energy and new capacity at some point. Site C would be the least expensive of the alternatives, and its cost advantages would increase with the passing decades as inflation makes alternatives more costly.

The Panel concludes that the Proponent has not fully demonstrated the need for the Project on the timetable set forth.

RECOMMENDATION 49
The Panel recommends that, if Ministers are inclined to proceed, they may wish to consider referring the load forecast and demand side management plan details to the BC Utilities Commission.

RECOMMENDATION 50
Regardless of its decision on Site C, the Province should update its guidance on the social discount rate or rates to be used for the analysis of societal costs and benefits for projects built or procured by public sector entities.

1 CEAA 2012, s. 5(1)(a)
2 CEAA 2012, s. 5(1)(b)
3 CEAA 2012, s. 5(1)(c)
4 CEAA 2012, s. 5(2)(a)
5 CEAA 2012, s. 5(2)(b)
Re: Need for and Alternatives to BC Hydro’s proposed Site C Project

Dear Minister Bennett and Minister de Jong,

It is our understanding that, in the coming days, you will be making a recommendation to Cabinet regarding a final investment decision (FID) with respect to BC Hydro’s proposed Site C Project. As you know, this decision has profound implications for the Provincial treasury, electricity consumers and the Treaty 8 First Nations.

The Treaty 8 Tribal Association (T8TA) and our First Nations have been deeply involved in the review of this proposed hydroelectric project. This includes participation in the environmental assessment process as well as review of BC Hydro’s most recent Integrated Resource Plan. The T8TA has also provided comments to the recent Industrial Electricity Policy Review and BCUC Review. These latter processes have been useful and beneficial to exploring important broader issues respecting electricity planning and regulation in the Province. We commend Minister Bennett for establishing these processes and for seeking broader consensus on how to proceed with developing and regulating the electricity sector going forward.

Following the release of the Site C Joint Review Panel Report in May of this year, the T8TA participated in several additional information exchanges with BC Hydro, concerning its updated electricity planning context as well as a number of outstanding issues from the environmental assessment process.

Based on these exchanges, our First Nations remain convinced that the Site C Project is not the most economic alternative for British Columbia, and that it involves unacceptable and unnecessary risks. Our reasons for reaching these conclusions are explained below.
1. The need for new power and energy

Minister Bennett was quoted in the media recently referring to “the 1100 megawatts of electricity that we need today.”\(^1\) We hope that the Minister was misquoted, as this statement represents a deep misunderstanding of the reality facing BC Hydro. In order to ensure that the Cabinet decision is based on a thorough understanding of the Crown Corporation’s situation, we begin with a brief review of BC Hydro’s current planning context.

Figure 1 below presents BC Hydro’s needs for future capacity and energy. It reflects the Crown Corporation’s most recent 2014 Load Forecast Update, including the Expected LNG (360 MW and 3000 GWh/year by F2021) and the No LNG scenarios, as well as Hydro’s current demand-side management (DSM) targets. In this figure, we have advanced the dates for the two Resource Smart capacity projects, GM Shrum Units 1-5 upgrades and Revelstoke 6, and also added natural gas resources (simple-cycle or combined-cycle gas turbines, as appropriate), up to the limit set by the 93% clean energy requirement of the Clean Energy Act (CEA).

The figure demonstrates that, even with Expected LNG, there is no need for additional new resources until F2027. In the event that expected LNG loads do not materialize, the date for additional new resources extends further out to F2031.

Indeed, our analysis shows that the full 1100 MW mentioned in the quote will not be required until F2035, with Expected LNG, or by F2038, with No LNG. Under BC Hydro’s low load scenario, the full 1100 MW will not be required until F2041.\(^2\)

The Resource Smart projects included in these graphs are low-cost capacity resources, and natural gas has become and is widely expected to remain a very low-cost resource. There is thus little doubt that, through F2027, the costs of this scenario remain far lower than one where Site C is commissioned in F2024.

These graphs do indeed demonstrate that, under current forecasts and with Expected LNG, BC Hydro will have significant new energy and capacity needs to meet in the 2030s. However, this finding must be tempered with the following realizations:

- BC Hydro’s DSM forecasts assume that annual gains in DSM will decline from over 1000 GWh/year in F2014 to 100 GWh/yr in F2024 to zero starting in F2034. In simple terms, BC Hydro anticipates that there will be no new technology innovations in this regard after F2024. As discussed further below, we consider this assumption to be entirely implausible.

- The twelve years between now and F2027 is a very long time in an electricity planning context. Most utilities only plan on a 10-year horizon. Thus, anywhere else in North America, BC Hydro’s planning picture would be summarized as: “no new capacity or energy required”. It is only to account for Site C that BC Hydro uses a 20- or 30-year planning period.

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2 BC Hydro. November 2013. Integrated Resource Plan, Appendix 6A, at pp. 6A-69 and 6A-73. (Not shown on Figure 1)
That said, we are convinced that, even based on all of BC Hydro’s assumptions, Site C remains less advantageous compared to several available alternatives, which are detailed below.

**Figure 1. Capacity and Energy Balances, Existing Resources + Resource Smart + Gas within headroom**

![Graph showing capacity and energy balances over time](image-url)
2. BC Hydro foresees no new energy conservation

As you know, the Clean Energy Act (CEA), adopted in 2010, includes the objective “to take demand-side measures and to conserve energy, including the objective of the authority reducing its expected increase in demand for electricity by the year 2020 by at least 66%” (s. 2(b)). We understand this objective to reflect the BC government’s view that DSM is the most cost-effective and environmentally benign way to meet energy needs, and should be aggressively pursued.

We therefore would expect that, in its planning after 2020, BC Hydro would continue to give a high priority to DSM. But it does not. We were surprised to learn that, in the planning scenario underlying BC Hydro’s recommendation to proceed with Site C, expected DSM gains drop off rapidly after 2020, falling to less than 20% of annual load growth by F2024 and to zero by F2034. As a result, cumulative energy savings as a percent of cumulative load growth also decline dramatically, as shown in the Figure 2, falling to about 35% by F2041. This compares to BC Hydro’s current DSM Target of 69% of load growth with Expected LNG and 78% with No LNG by F2021.3

![Figure 2. Cumulative DSM Gains as a Percentage of Load Growth](image)

This is not because BC Hydro intends to cease investing in DSM. In fact, after reducing DSM expenditures in the next few years, it forecasts increasing them from F2017 through F2027, and then reducing them gradually, as shown in Figure 3.

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BC Hydro explains these declining returns, despite substantial funding, by noting that future DSM savings that are deducted from BC Hydro’s Load Forecast will need to replace the savings that were previously acquired. BC Hydro assumes that the average DSM program life is about 15 years, depending on the program and the technology employed. At the end of this period, the savings are removed from the DSM plan since they are no longer incremental to what would have otherwise occurred. Thus, BC Hydro believes that in the late 2030s it will have to spend over $200 million per year simply to maintain the gains from past DSM programs.

As long as energy efficiency innovation continues to advance, these future expenditures can be expected to generate additional energy savings. Thus, underlying BC Hydro’s forecast is an assumption that innovation in energy efficiency technologies will grind to a halt.

We find that position, quite simply, ridiculous. LED lights, time-of-use prices, programmable thermostats, community energy planning, micro-grids, real-time data analytics, and direct load control are just a few of the many social and technological energy management innovations of recent years, and there is no reason to believe that human inventiveness will come to an end over the next decade. In fact, the pace of energy innovations is increasing rapidly, not declining. The following recent expert testimony before the Manitoba Public Utilities Board speaks to this issue:

The challenge of DSM for planning purposes, then, becomes the challenge of predicting innovations: we know they will happen, but we don’t know exactly how or how much. Yet the reverse is true too: we know that a static view – one in which future DSM savings are limited to the savings opportunities available today – is
wholly inappropriate for a long-term planning horizon, much less one covering the coming 20 years.

Yet this static view, which implicitly assumes zero innovations over the coming two decades, lies at the root of two important documents in the current proceeding: Manitoba Hydro’s Power Smart plan, which anticipates a significant reduction in new savings over the longer term, and EnerNOC’s potential study, which similarly assumes significant reductions in DSM potential over time. In both cases, a very real methodological challenge has led to a very unrealistic prognosis for the future of DSM.4

Indeed, this belief in the end of technological innovation is symptomatic of a methodological error made systematically by BC Hydro. Many resources were excluded from its Integrated Resource Plan because they are “not ready for prime time”. For example, in the case of capacity-focused DSM, geothermal energy, solar energy and other resources, BC Hydro chose to exclude them entirely from its long-term plan because they are not yet fully mature.

This reasoning would be perfectly appropriate for a three-year operational plan, where the utility’s obligation to provide reliable service is paramount. It would be wrong for a utility to rely, in the short term, on technologies that have not yet been proven, but it is just as wrong to exclude them entirely on that same basis from a long-term plan.

The Joint Review Panel for Site C made a similar observation:

> It is not unreasonable to hope that every succeeding IRP will increase the contribution of innovations seen today as not well enough understood to be counted upon.5

BC Hydro’s approach is that it is better to be “conservative” and not count on resources until they are proven. However, from a long-term planning perspective, this approach can be dangerous since it inevitably underestimates the future availability of cost-effective resources, and so tends toward over-supply.

A flagrant example of this type of error was made by Hydro-Quebec in 2002, when it held a tender for long-term supply resources, based on a conservative estimate of future DSM savings. As it turned out, DSM savings continue to be vastly greater than those counted on in 2002.6 As a result (and combined with other factors), Hydro Quebec Distribution has over-acquired resources and expects to be in surplus until the mid-2020s. The cumulative surplus over the next decade is estimated at over 75,000 GWh, with rate impacts in the billions of dollars as a result of the need to export these surplus resources at far lower prices on the export markets.

There is no need for BC Hydro to make firm decisions in 2014 on how to serve its loads 20 years from now. The world today is very different than it was 20 years ago, and there is every reason

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to believe it will be very different as well, in very unpredictable ways, in 2034. **The decision to commit to Site C, a large project with a long lead-time, creates significant risks of over-supply that are not adequately captured in BC Hydro’s analysis.**

### 3. Site C is a high-cost option

BC Hydro estimates the long-term levelized cost of the Site C Project to be $83/MWh at the point of interconnection and $94/MWh delivered to the Lower Mainland. Compared to market prices, this is indeed a very expensive resource.

According to data presented in its 2013 IRP, the market price for BC Hydro purchases at the US Border, under the medium scenario, will remain under $40/MWh until 2027. The selling price is even lower, as shown in Figure 4.

![Figure 4. Site C levelized cost compared to forecast market prices](image)

Thus, insofar as Site C could be avoided or delayed by relying on market-priced power, the costs to BC consumers would be dramatically reduced.

As you know, the self-sufficiency requirement of the CEA currently prevents BC Hydro from relying on market purchases to meet its future needs. However, as we demonstrate below, there is another option that would allow BC Hydro to access a substantial bloc of market-priced energy while respecting the intent of the CEA.

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4. **Site C is a high-risk option**

BC Hydro purports to demonstrate that Site C is the least-cost solution to its long-term needs. However, careful analysis demonstrates that the claimed benefits are slight, and would occur only under a series of assumptions that are exceedingly unlikely to remain true into the future. Under more reasonable assumptions, there is a very real risk that the costs of Site C will exceed those of the alternatives, resulting in a long-term adverse effect on rates as a result of the large capital expenditure associated with Site C and the large surplus it would inevitably create. Looking back from the 2030s, Site C would be seen as a very expensive choice considering the affordability of the alternatives, which will only improve over time. **We cannot afford to place the indefinite high-cost burden of Site C on future generations and on the future economy of our Province.**

Figure 5 compares the evolution of cumulative net present value costs for portfolios with and without Site C, based on BC Hydro’s analysis and assumptions.

### Figure 5. Cumulative net present value costs, Site C vs. Clean + Thermal Portfolio (no LNG)

This figure, based on data generated by BC Hydro’s System Optimizer software package, demonstrates that, **until F2038, the cumulative present value portfolio costs without Site C are in fact lower than those with Site C.** Beyond the “crossover point” in F2038, the Site C portfolio does indeed show a lower net present value, but for many years, the expected benefits of the Site C portfolio remain slim. Furthermore, this crossover point is dependent on a
number of highly questionable assumptions. Should BC Hydro be proved wrong on any of these assumptions, the crossover point would be delayed or would never occur. In such a scenario, the decision to proceed with Site C would cause British Columbians to incur costs higher than those of readily available alternatives, for decades into the future.

It is important to understand that, because the export market prices are dramatically lower than the unit cost of energy from Site C, the surplus from Site C can only be exported at a considerable loss, resulting in a substantial burden on ratepayers until such time as that energy is fully utilized in BC. As such, it is necessary to consider BC Hydro’s assumptions respecting the various factors that could delay this full utilization of the Site C surplus, as well as the utility’s assumptions regarding the cost and progression of the alternatives. In general, BC Hydro’s scenario is based on the following assumptions:

- An optimistic load forecast – If load growth is lower than expected, the crossover date will be even farther out since BC Hydro will have overbuilt and will have to export the surplus for a longer period of time. In the low load scenario contemplated in the IRP, the crossover point does not occur, as the alternative portfolio remains cheaper than Site C throughout the planning period.\(^8\)

- Expensive wind power – **BC Hydro assumes there will be no further declines in real wind costs before F2041**, and that the real cost of wind generation will remain equivalent to what it was in 2012. However, since 2009, turbine costs have declined substantially, on the order of 20% to 40%.\(^9\) Turbine performance continues to improve, and some North American jurisdictions are reporting overall project cost declines on the order of 60% since 2009. In the IRP, BC Hydro acknowledges only a portion of these recent cost declines and performance improvements.\(^10\)

In its exchanges with BC Hydro, the Treaty 8 Tribal Association presented the utility with Figure 5, below, from the US National Renewable Energy Laboratory, requesting the Crown Corporation’s views. The figure illustrates 18 different projections of the future levelized cost of energy (LCOE) from wind resources. All but one of these 18 projections forecast substantial reductions in the real cost of wind energy.

BC Hydro acknowledged that its view was the outlier in the graph, namely the uppermost blue line, according to which there would be no future declines in the real cost of wind energy, and the cost of wind in 2030 would be 100% of its cost in 2011. However, all other industry observers consulted, including the US Department of Energy and the Energy Information Administration, believe that wind costs will decline by an additional 20% to 30% in real terms by 2030, as technology improves. Since wind resources comprise much of the energy in the alternative portfolio to Site C, if real wind costs decline, the crossover date will be farther out, if it occurs at all.

\(^8\) BC Hydro. November 2013. Integrated Resource Plan, Appendix 6A, Table 4, at p. 6A-37. In the low load (small gap) scenario, the non-Site C portfolios cost approximately $1B less than the Site C portfolios.


In response to a request from the Association, BC Hydro modeled a scenario following a more mainstream view of future wind costs in BC, involving a 20% decline in the real unit energy cost of wind resources between F2015 and F2030. The result of this single change altered the cumulative present value difference by about $400 million in favour of the alternative portfolio.

Figure 6. Estimated range of wind LCOE energy cost projections

- Very pessimistic DSM forecasts — As noted above, **BC Hydro believes that additional DSM savings will decline rapidly during the next decade and disappear entirely by F2034.** If BC Hydro is wrong, and new technologies create new opportunities to reduce energy consumption, the crossover date will be farther out if it occurs at all, as it would be more affordable to conserve.

- Capacity-focused DSM will not prove effective — As called for by Recommended Action #2 of its IRP, BC Hydro has recently carried out a pilot study of direct load control (DLC), a particularly effective form of capacity-focused DSM. The study, carried out for the Kamloops region, concluded that the potential for DLC is considerably greater than the 300 MW of capacity required by BC Hydro by F2023. However, **BC Hydro continues to decline to include any capacity-focused DSM savings in its long-term plan, because it would be “premature” to do so.** Should any such capacity savings materialize, the

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13 The study was based on a 4-hour curtailment period, and BC Hydro has explained that, in part because of the downstream flow restrictions affecting all generating facilities on the Peace River, it also has 8-hour and 16-hour requirements to meet shoulder capacity needs. However, the addition of gas capacity within the available headroom, which can be operated as required, can address this issue.
crossover date by which Site C starts to show a financial advantage over the alternative portfolio will be even farther out, since it would be more affordable to implement these savings than to develop Site C.

- **Distributed generation will not occur** – BC Hydro believes that solar power will not be cost-effective in British Columbia before F2041, and, more broadly, that BC consumers will never produce significant amounts of their own electrical energy. Industry observers disagree, believing that the cost of solar will decline such that it will be competitive for net metering in BC some time during the 2020s. To the extent customers produce their own electricity, the surplus created by Site C will persist, increasing its costs to ratepayers relative to the alternatives.

- **Smart Meters have limited utility** – BC Hydro believes that Smart Meters will never be used for anything other than catching crooks. In its Business Case for Smart Metering Infrastructure (SMI), BC Hydro claimed that voluntary time-of-use rates made possible by those meters would be adopted by 30% of the population by 2015, and would decrease their capacity needs by 10%. Furthermore, in-home displays were expected to be in 30% of homes, with savings of 4% of total energy consumption. Now, however, these goals have been abandoned. In its responses to our questions, BC Hydro made clear that the only gains expected from Smart Meters are from Theft Reduction and VAR and Voltage Optimization. Should the previously expected gains from SMI in fact materialize, they would add to the surplus created by Site C, defer the date when Site C’s energy is fully required in BC, and so increase the period during which Site C results in costly energy exports.

- **Geothermal energy will not be developed in British Columbia** — BC Hydro’s IRP clearly indicates the cost-effectiveness of at least 500 MW and 4,000 GWh/year of geothermal resources in BC, at a unit energy cost of $100/MWh. Though this cost exceeds the unit energy cost of Site C, the geothermal resource could be developed as required so as to avoid the costly surplus inherent in developing Site C, resulting in substantial benefits for ratepayers. However, BC Hydro continues to hold the following views:

  BC Hydro has not seen any successful geothermal development in B.C. to date and it is still highly uncertain and speculative to rely upon an undeveloped resource in B.C. to meet load requirements for which investment decisions must be made now.

  Of course, no investment decision must be made now, unless it is to begin construction of Site C for an in-service date of F2024. There remains time to resolve the “uncertain and speculative” nature of the undeveloped geothermal resource in B.C. In addition, BC

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15 Ibid., at p. 28.


17 Letter from Trevor Proverbs, First Nations Engagement Director, to Rick Hendriks for the Treaty 8 Tribal Association, December 5, 2014, at p.4.
Hydro neglects to note the reasons for the lack of geothermal development in the Province, which were made clear in the JRP Report:

The 1983 BCUC decision on Site C advised BC Hydro to explore the possibilities of unconventional energy sources, including geothermal energy, but little was done. At that time, BC Hydro’s budget for such exploration was about $20 million, mostly concentrated on the geothermal resources near Meager Creek. In testimony, BC Hydro characterized its present level of effort as “under $100,000 [per year].” Moreover, BC Hydro said “we don’t really have funding to do R&D... In fact we’re expected not to do that.” However, section 2(d) of the Clean Energy Act states that it is a Provincial objective “to use and foster the development in British Columbia of innovative technologies that support energy conservation and efficiency and the use of clean or renewable resources.” ...

BC Hydro is not solely to blame for this lack of performance. Governments used to fund geological exploration. In the recent past, B.C. has enjoyed plentiful low-cost electricity, making the exploration of alternative renewable sources seem less than urgent. But times have changed. Failure to ramp up this work a decade ago means that BC Hydro is without a well understood opportunity in the present.

The Panel concludes that a failure to pursue research over the last 30 years into B.C.’s geothermal resources has left BC Hydro without information about a resource that BC Hydro thinks may offer up to 700 megawatts of firm, economic power with low environmental costs. 18

Should geothermal energy be developed in BC anytime over the next 20 years, the crossover date would be even farther out or non-existent, since it would be more affordable to develop geothermal resources as they are required than to develop Site C with its costly surplus.

• **There will be no construction cost overruns for Site C** – It is rare for large-scale hydroelectric projects not to show cost overruns. Considering that BC Hydro has not developed a large-scale hydroelectric project in decades, the most appropriate comparison for the purposes of potential cost overruns is more recent large-scale hydroelectric development in neighbouring northern jurisdictions. The cost of Manitoba Hydro’s Keeyask Project increased 5% just within the period between the environmental assessment and commencement project construction, with the potential for further cost increases during the 5-year construction period. 19 In Labrador, the cost of Nalcor Energy’s Muskrat Falls Project and its associated Labrador Island Transmission Link have risen from $5.0 billion in 2010 to $7.0 billion in 2014, an inflation-adjusted (i.e. real cost) increase of 28%. 20,21 The higher the actual construction cost, the longer the alternatives will remain cheaper than Site C.

20 Nalcor Energy. 2011. Muskrat Falls Presentation to the PUB, at p. 37
• Exchange rates — BC Hydro assumes a constant exchange rate of $0.9693 USD/CAD through F2041. It has stated that it does not need to address exchange rate risk directly, because it is subsumed in market price scenarios. This thinking is simplistic, potentially risky and would not be tolerated in the private sector.

The value of the Canadian dollar is already 10% lower than the long-term value assumed by BC Hydro. To the extent that Site C construction costs are priced in US dollars, the capital cost of the project has already increased. For example, including inflation and interest during construction, the cost of power facilities alone was $1.4 billion before the current slide in the Canadian dollar began.

In fact, it is the pattern of future exchange rate fluctuations that influences the economics of Site C. If the Canadian dollar continues to decline over the next 5 years only to appreciate after 2020, the consequences could be severe. Capital costs would be higher, but then, just as Site C energy starts to flood the market, a rising Canadian dollar would reduce export revenues. This scenario illustrates that there are exchange-related risks that have not been addressed and that could materially affect the cost of Site C in relation to the alternatives.

5. The Canadian Entitlement and the self-sufficiency requirement

BC Hydro’s import capacity is 2000 MW from the US, and imports of 2000 MW are not uncommon. In fact, in the past, BC Hydro has imported as much as 8,400 GWh in a single year. There is thus no technical obstacle to importing large amounts of power.

However, BC Hydro cannot plan on using these resources because of the self-sufficiency requirement set out in s. 6(2) of the CEA, which requires that BC Hydro plan to meet all energy needs with in-province generation. This excludes not only energy purchases from the wholesale market, but also the Canadian Entitlement under the Columbia River Treaty.

The Canadian Entitlement varies from year to year. In F2014, it consisted of 1,330 MW of hydroelectric capacity and 4,425 GWh of energy. These amounts represent “half of the extra power capability at generation facilities in the U.S. that results from the improved water regulation made available by the Columbia River Treaty.” The Canadian Entitlement is owned by the Province of B.C. and is marketed on its behalf by Powerex at low market prices similar to those shown in Figure 4, above. However, because the turbines generating the electricity are

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located in the United States, under the self-sufficiency requirement as formulated in the CEA, this energy is not produced by “generating facilities within the Province.” As a result, this hydropower, which reflects the contribution of reservoirs located in British Columbia to the hydropower produced on the Columbia River system, cannot be relied upon by BC Hydro for long-term planning purposes. As such, it cannot be used to displace far more expensive resources, such as Site C.

It should be noted that ss. 35(i) and 6(3) of the CEA do allow the government to authorize BC Hydro by regulation to enter into electricity import contracts otherwise barred under s. 6(2).

Subsection 6(3) of the CEA provides an exception to the self-sufficiency requirement found in subsection 6(2). The LGIC may by regulation authorize BC Hydro to enter into contracts for purposes of not meeting the self-sufficiency requirement.27

In fact, in its 2013 IRP, BC Hydro announced that it would seek such a regulation to allow it to rely on market purchases of capacity from F2019 to F2023.28

In its IRP process, BC Hydro had to assume that the self-sufficiency criterion would remain unchanged throughout its planning period. The Joint Review Panel faced a similar constraint. The Government of British Columbia, however, is not so constrained, given its executive power to allow exemptions to the self-sufficiency requirement.

The Joint Review Panel spoke only briefly of the self-sufficiency requirement. However, its comments raise questions as to whether or not this criterion is in the public interest of British Columbians:

Taken literally, this [self-sufficiency requirement of the CEA] means a B.C. disconnected to the outside world, a vision of autarchy truly strange for a province that relies on trade, and a long way from its recent history. (It could also explain the neglect of geothermal opportunities.)

Minor relaxations could mean being connected for reliability or for diversity exchange, which are current practices apparently not condoned by the regulation, or for multi-year balance, all of which seem consistent with the intent if not the drafting of the regulation. … 29

The Industrial Energy Policy Review panel established by Minister Bennett in January 2013 raised the same issue in its Final Report:

As BC Hydro’s surplus diminishes, Government should consider whether a requirement for self-sufficiency is consistent with a long-run approach to least cost electricity prices.30

28 Ibid.
29 Site C Joint Review Panel. May 2014. Report of the Joint Review Panel Site C Clean Energy Project BC Hydro, at pp. 304-305. In the same section, the JRP also questioned the current treatment of the Columbia River Treaty and the natural gas “headroom” policy, both of which constrain rational planning options.
The Government’s formal response suggested that it is open to reviewing this restraint in the future:

BC Hydro is currently in surplus. While not under consideration at this time, this recommendation could be considered as energy forecasts change.31

However, when the construction of the Site C Project begins, the horse will already have left the barn. Once Site C is commissioned, B.C. Hydro will face energy surpluses into the 2030s and potentially longer. The economic benefit that would flow from the repatriation of the Canadian Entitlement under the Columbia River Treaty would be lost. Powerex would also be in the disadvantageous position of selling the Canadian Entitlement at extremely low market prices.

The self-sufficiency requirement was apparently designed in large part to make it impossible to circumvent BC’s clean energy legislation by importing high-GHG power. The Canadian Entitlement, however, consists of hydropower, the environmental costs of which are already borne by British Columbians. Adopting a regulation allowing the import of the Canadian Entitlement could not be seen as compromising BC’s climate policies or its goal of energy self-sufficiency.

The consequences of the self-sufficiency criterion were evaluated in the BC Hydro Review in 2011:

The panel recognizes that the economic and energy situations have changed, and that the existing self sufficiency definition may be overly conservative and place an undue burden on ratepayers. The panel recommends that BC Hydro and the province evaluate alternative definitions and timelines for self-sufficiency that meet the needs of the province and ratepayers in a way that is sustainable for the long term.32

To cast more light on this issue, we have prepared a scenario that meets BC Hydro’s current load forecast plus Expected LNG (360 MW and 3,000 GWh/yr) assuming that the Canadian Entitlement is exempted by regulation under CEA s. 6(3) from application of the self-sufficiency requirement. Given the uncertainties surrounding the renegotiation of the Columbia River Treaty, we have limited the Downstream Benefits in this scenario to 50% of the energy and capacity currently available.33

Were the Government of BC to do so, adopting a regulation exempting the Canadian Entitlement from application of the self-sufficiency requirement would immediately defer the need date for new capacity resources (beyond gas headroom) to F2033 for capacity and to F2031 for energy, as shown in Figure 7 below.

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33 Given the importance of the Treaty to US system operations, T8TA considers it implausible that the Americans would abrogate the treaty. However, it is possible that the Downstream Benefits will be reduced. (See: U.S. Benefits from the Columbia River Treaty – Past, Present and Future: A Province of British Columbia Perspective, BC Ministry of Energy and Mines, June 25, 2013. http://blog.gov.bc.ca/columbiarivertreaty/files/2012/07/US-Benefits-from-CRT-June-25-132.pdf)
Figure 7. Capacity and Energy Balances, Existing Resources + Resource Smart + Canadian Entitlement + Gas Within Headroom
Furthermore, one of the additional benefits of exempting the Canadian Entitlement from the self-sufficiency requirement is that doing so would reduce the overall need in BC for electricity generated from natural gas, delaying by several years the development of gas turbines, which are contemplated for development later this decade in all portfolios, including those containing Site C. Indeed, it is paradoxical that, in this context, the application of the self-sufficiency principle as embodied in s. 6(2) would result in British Columbia relying on burning natural gas rather than using its own hydropower, because it happens to be generated by turbines in the United States.

We have also prepared scenarios that include the Canadian Entitlement while also meeting the additional demands beyond F2031 through a combination of additional DSM, wind, biomass and geothermal resources. According to our analysis, the present value cost of these alternative portfolios are at least $2 billion less than that of the Site C + Clean + Thermal portfolio favoured by BC Hydro.

We asked BC Hydro to prepare its own analysis of these scenarios, using its System Optimizer software package. Unfortunately, it declined to study any scenario that included repatriation of the Canadian Entitlement. We find this refusal regrettable.

BC Hydro explained its refusal to examine the implications of repatriation of the Canadian Entitlement (CE) in the following terms:

> [T]he definition of self-sufficiency has essentially remained the same since 2007 when Special Direction No. 10 was issued, with sole exception of the move to Heritage hydro average water condition planning in 2012. BC Hydro is not prepared to speculate on changes to existing legislation, and has consistently refused to run scenarios which do not meet existing legal requirements, including refusing a request from the BCUC in 2008 as part of its review of BC Hydro’s 2008 LTAP. T8TA has provided no evidence that the B.C. Government is contemplating the CE as a long-term planning resource available to BC Hydro because no such evidence exists. In BC Hydro’s view, B.C. Government approval of the 2013 IRP demonstrates otherwise. This comment carries over and forms part of why BC Hydro sees no basis to run T8TA Scenarios 2 and 6.34

Thus, in the absence of explicit evidence that the B.C. Government is contemplating the Canadian Entitlement as a long-term planning resource, BC Hydro considers itself barred from examining the implications of so doing.

How, then, would the Provincial Government ever become aware that it could avoid the environmental and Treaty infringement consequences of the Site C Project, avoid borrowing billions of dollars and avoid major rate impacts by repatriating BC hydropower, if BC Hydro believes it is barred from even mentioning this possibility unless explicitly asked to do so by the Government?

34 Letter from Trevor Proverbs, First Nations Engagement Director, to Rick Hendriks for the Treaty 8 Tribal Association, December 5, 2014, at p.2.
The BCUC order cited earlier in the letter only states the obvious: that, given the wording of s. 6(2) CEA, the Canadian Entitlement is not considered a domestic resource. However, we have been unable to find any reference from BC Hydro, the BCUC or the BC Government ever explaining why the hydropower from BC reservoirs that constitutes the Canadian Entitlement should be considered a foreign resource.

How can government make a reasoned decision, if the information before it excludes an option that would dramatically reduce costs while respecting the intent of the existing legislation?

6. Summary: Site C achieves no compelling and substantive objective

As noted at the outset of this letter, we remain convinced that the Site C Project is not the most economic alternative for British Columbia. There is no immediate need for the proposed project. The available evidence indicates that the purported need used to justify Site C, even with Expected LNG, will not materialize until F2027, and with No LNG until F2031. Under BC Hydro’s low load scenario, the full 1100 MW provided by Site C will not be required until F2041.

BC Hydro asserts present value cost benefits of Site C on the order of several hundred million dollars compared to the various alternative portfolios over a planning period to F2041. More recently, BC Hydro has been reframing the purported economic benefits of Site C compared to the alternatives using an 80-year planning period, long enough to include the entirety of the 70-year financial life and debt-repayment period for Site C. It now claims that the comparative economic benefits of Site C over an 80-year planning period are on the order of $2 billion.

The use of an excessively long planning period deliberately masks the reality that any potential economic advantage of Site C occurs, at the earliest and if at all, several decades into the future. In its recent application to the Manitoba Public Utilities Board, Manitoba Hydro tried a similar strategy. The Manitoba PUB was unequivocal in expressing its rejection of Manitoba Hydro’s 78-year planning period for evaluating alternatives to large hydro projects, indicating the following as the very first paragraph in the Board’s recommendations to the Government of Manitoba:

As a result of its review, the Panel rejects Manitoba Hydro’s Preferred Development Plan, as well as Manitoba Hydro’s suggestion to consider pathways that map out a 78-year future, as the Panel sees Manitoba Hydro’s long-term future projections as highly speculative and too uncertain. [emphasis added]

The conclusions reached by BC Hydro concerning the potential economic advantages of Site C compared to the alternative portfolios are dependent on a series of implausible and dubious assumptions that include the following:

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• future gains in demand-side management will drop off rapidly after F2020, falling to less than 20% of load growth by F2024 and to zero by F2034;
• there will not be any future energy efficiency or technology innovations beyond the next decade;
• no capacity-focused demand-side management will be viable before F2041;
• there will be no further declines in real wind costs between the estimates in the BC Hydro November 2013 IRP and F2041;
• solar power will not be cost-effective in British Columbia before F2041;
• smart meters will never be used for anything other than catching crooks; and
• geothermal energy will not be developed in British Columbia before F2041.

In addition to the available cost-effective alternatives to Site C under existing laws and regulations, the Province also has available to it the Canadian Entitlement under the Columbia River Treaty. On the order of 1300 MW and 4.4 TWh, the Canadian Entitlement is owned by the Province of B.C. and sold at market prices that are currently low and are expected to remain low indefinitely. Currently, the self-sufficiency requirement of s.6(2) of the Clean Energy Act bars consideration of this capacity and energy for use in BC since it is not produced by “generating facilities within the Province.” As such, it cannot be used to displace far more expensive resources, such as Site C.

In its IRP process, BC Hydro had to assume that the self-sufficiency criterion would remain unchanged throughout its planning period. The Joint Review Panel faced a similar constraint. The Government of British Columbia, however, is not so constrained, and adopting a regulation exempting the Canadian Entitlement from application of the self-sufficiency requirement would immediately defer the need date for new capacity resources (beyond gas headroom) to F2033 for capacity and to F2031 for energy.

We have estimated the potential benefits to ratepayers of enacting such a regulation to repatriate the Canadian Entitlement to be at least $2 billion compared to the Site C portfolio preferred by BC Hydro. Importantly, unlike the benefits espoused by BC Hydro in relation to Site C, which are in the distant future and highly uncertain, those of a portfolio including the Canadian Entitlement would be immediate, substantial and highly certain since they occur in the earliest years of the planning period and not several decades hence or not at all.

Our First Nations remain available to continue discussions with BC Hydro and the Province respecting the need for and alternatives to the proposed Site C Project. We believe that all parties gained considerable knowledge respecting the alternatives, including their technical, economic, financial and environmental attributes as a result of these respectful discussions and exchanges of information. Despite best efforts, we were unable to convince BC Hydro to model several alternative portfolios contemplating more realistic future DSM targets, reasonably priced alternative resources, and repatriation of the Canadian Entitlement.
There is much at stake for the Government of BC, for our First Nations, and for our future relations. A cost-effective solution that does not involve Site C is readily available should BC Hydro and the Provincial Government choose to consider it seriously.

Chief Lynette Tsakoza
Prophet River First Nation

Chief Roland Willson
West Moberly First Nations

cc: Treaty 8 First Nations – Chiefs
MLIB – Chief Derek Orr
Government of BC – Treasury Board
Honourable John Horgan – Leader, NDP Official Opposition
Dr. Andrew Weaver – MLA, B.C. Green Party
Reassessing the Need for Site C

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April 2017
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Full report available at: https://watergovernance.ca/projects/sitec/
EXECUTIVE SUMMARY

The Government of British Columbia and its wholly owned utility, BC Hydro, have embarked on an $8.3 billion large-scale hydroelectric project at Site C on the Peace River in northeastern British Columbia. The Project is currently in the early stages of construction with a scheduled commissioning date of 2024.

The purpose of this Report is to provide deeper insight to government, policy-makers, and the general public regarding the economics of the Site C Project. The Report addresses whether the Site C Project is past the “point of no return” from an economic perspective.

The Report incorporates into our analysis several key changed circumstances since the initial comparison of the Site C Project with the alternatives was performed by BC Hydro in 2013. These include: a decline in the cost of the alternative resources to the Site C Project (including wind); a substantial reduction in BC Hydro’s forecasted need for electricity in 2024 and beyond; and an increase in the cost of the Site C Project.

Our analysis: We analyze whether it would be economically preferable to a) complete, b) cancel or c) suspend the Project. We examine these three options in the context of different forecasts for electricity requirements, possible cost overruns in the Site C Project, different levels of conservation and efficiency, and a range of electricity prices in the electricity export markets. We also consider whether cancelling the Site C Project is preferable to suspending the Project. Our analysis considers that BC Hydro will have spent $1.87 billion as of June 30, 2017, and that cancelling or suspending the Project will entail additional construction cancellation, demobilization, and suspension costs.

Our findings are: 1) The decision to approve the Site C Project in 2014 will cost ratepayers on the order of $1.4 to $1.7 billion dollars more than had an alternative portfolio of resources been pursued at that time. 2) Our analysis indicates that cancelling the Site C Project as of June 30, 2017 would save between $500 million and $1.65 billion, depending on future conditions. 3) Suspending the Site C Project is preferable to cancelling the Project by up to $350 million. Both cancelling and suspending are preferable to continuing with the Site C Project.

Our recommendation is: Suspend the Site C Project, and refer the Project to the BC Utilities Commission for a full review.

1 The Program on Water Governance at the University of British Columbia has previously published several reports on the Site C Project: http://watergovernance.ca/projects/sitec/
ABOUT THE AUTHORS

Dr. Karen Bakker is Professor, Canada Research Chair, and Founding Director of the Program on Water Governance at the University of British Columbia (www.watergovernance.ca). The author of over 100 academic publications on water-related issues, Dr. Bakker has acted as an advisor and consultant to national and international organizations in North America, Europe, and southeast Asia for the past two decades.

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Philip Raphals is cofounder and executive director of the Helios Centre, a non-profit energy research and consulting group based in Montreal. Over the last 25 years, he has written extensively on issues related to hydropower and competitive energy markets, and has appeared many times as an expert witness before energy and environmental regulators in several provinces.

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1. Introduction and Summary

1.1 Introduction

This report is part of an initiative of the Program on Water Governance at the University of British Columbia. The Program on Water Governance (watergovernance.ca) conducts interdisciplinary research on water sustainability, and makes this research available to the public. In addition to our academic publications, we publish briefing notes and reports, with the goal of fostering dialogue on water policy with communities and decision-makers.

This report follows on prior work produced by the Program on Water Governance in relation to the Site C Project. This prior work includes four reports (available at watergovernance.ca/projects/sitec/), which address gaps in the review process for Site C:

- Briefing Note Report #1 – First Nations and Site C
- Briefing Note Report #2 – Assessing Alternatives to Site C (Environmental Effects Comparison)
- Briefing Note Report #3 – The Regulatory Process for the Site C Project
- Briefing Note Report #4 – Comparative Analysis of Greenhouse Gas Emissions of Site C versus Alternatives

The purpose of this fifth report is to provide deeper insight to government, policy makers and the general public regarding the development of the Site C Project, an $8.335 billion large-scale hydroelectric project on the Peace River in northeastern British Columbia. Specifically, the report considers the factors that led to the construction of the Site C Project, the factors that have changed since it was approved, and the merits of the following options:

a) continue with construction of the Site C Project to completion as scheduled;
b) cancel the Site C Project in order to develop alternative resources; or
c) suspend the Site C Project and develop alternative resources as needed, but leave open the possibility of continuing the Site C Project if circumstances warrant.

1.2 Methods and Sources

This Report relies primarily on information made public by BC Hydro, including its 2013 Integrated Resource Plan (IRP) and its 2016 Revenue Requirements Application (RRA)
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currently under review by the BC Utilities Commission.²

Scenario analysis was performed through an Excel-based model constructed by the authors. All tables and charts not otherwise identified have been produced by the authors themselves, using this model.

Like any analysis looking 20 years into the future, the forecasts underlying these analyses are highly uncertain. Except otherwise noted, the forecasts used are the most recent forecasts made public by BC Hydro. In most cases, we have used low-mid-high scenarios to explore the implications of these uncertainties.

The Report goes to considerable lengths to explain the inputs and assumptions used in its models. We welcome feedback on our methods, inputs and assumptions.

1.3 Summary

Section 2 explores the historical and regulatory context justifying the decision to proceed with the Site C Project, and provides background for the sections that follow. In December 2014, the Provincial Government justified the significant adverse environmental effects of the Site C Project on the premise — which this Report demonstrates to be incorrect — that the Project would deliver energy and capacity at lower GHG emissions and lower costs than the available alternatives.

Section 3 analyzes the evolution, since Site C was approved, of BC Hydro’s forecasts of British Columbia’s future electricity needs. This section demonstrates that BC Hydro’s 2012 Load Forecast has collapsed. As a result, completing the Site C Project in F2024 would result in a large energy surplus that would last almost a decade — or more, if load growth is lower than forecast by BC Hydro.

Our analysis finds that the decision to build Site C was based on a strikingly high load forecast made by BC Hydro in 2013, which was (a) notably higher than similar estimates made before or since (on the order of 5,000 GWh/year) and (b) largely excluded the potential for energy conservation. BC Hydro’s current forecasts are much lower, and indicate that Site C will produce surplus electricity that will have to be sold at a loss for many years after commissioning.

Section 3 also analyzes BC Hydro’s load forecasting history over the past three decades, and finds that 85% of the 26 load forecasts prepared by BC Hydro since Site C was first proposed (in the 1980s) have been overestimates. The report also discusses the reasons why a high-load scenario now appears exceedingly unlikely, due to (a) continuing delays to several mining, LNG, and oil and gas projects; (b) fewer new mining and oil and gas projects because of low commodity prices; (c) lower than expected housing starts; (d) lower residential and commercial demand; (e) somewhat

² As part of the regulatory review process for setting rates, BC Hydro released information to the BC Utilities Commission in 2016 and 2017. The documents are available on the BC Hydro website and on the BCUC website (See “British Columbia Hydro and Power Authority ~ F2017 to F2019 Revenue Requirements Application ~ Project No. 3698869” at: http://www.bcuc.com/ApplicationView.aspx?ApplicationId=533).
higher electricity prices; and (f) the ongoing effects of energy conservation and demand management. Moreover, our research shows that “electrification” of the economy will increase demand but not to justify Site C on the current timeline. BC Hydro’s own forecasts indicate that electricity demand from electrification will be relatively modest into the 2030s.

Section 4 investigates the costs of continuing to develop the Site C Project to completion as scheduled, including an analysis of the risks and implications of cost overruns. Although the Site C Project so far remains on budget, we summarize the prior experience of BC Hydro and other Crown corporations, which suggests that cost overruns in large-scale hydroelectric and transmission projects are common and potentially substantial.

Section 4 also analyzes the economic implications of proceeding with the construction of the Site C Project under BC Hydro’s current load forecast, by calculating the losses resulting from exporting the energy surplus at prices far below the cost of production. Over the years of expected surplus, the total export losses are projected to be almost $950 million for the mid-load scenario. Under BC Hydro’s low-load forecast, the cumulative losses would be on the order of $2.7 billion by 2036 and would continue to increase thereafter.

The additional cost of GHG emissions is also presented in Section 4. BC Hydro includes the cost of construction phase GHG emissions in its estimate of the cost of the Site C Project, but not those of the operations phase emissions. Using the price of $50/tonne in 2022 announced by the Government of Canada, we estimate the cost associated with GHG emissions from the Site C reservoir to peak at about $32 million per year in 2026, and to total approximately $166 million (in real 2016 $).

Under these circumstances, the question arises: Should construction of the Site C Project be suspended or cancelled? To answer this question, the final three sections of the report assess and compare the financial implications of the following three options, using June 30, 2017 as the decision date:

a) Continue with construction of the Site C Project to completion as scheduled;

b) Cancel the Site C project in order to develop alternative resources; or

c) Suspend the Site C project and develop alternative resources as needed, but leave open the possibility of continuing the Site C Project if circumstances warrant.

Section 5 analyzes the costs of cancelling or suspending the Site C Project. BC Hydro will have incurred on the order of $1.87 billion in sunk costs to develop the Site C Project by June 30, 2017. The analysis considers these sunk costs as well as costs related to contract cancellation and demobilization, and potential site maintenance while the project is in suspension. Alternative resources considered include energy- and

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3 In a previous study, we explored in detail the expected GHG emissions of the Site C Project. Report available at: https://watergovernance.ca/projects/sitec/report-4-site-c-comparative-ghg-analysis/
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capacity-focused demand-side management, as well as supply-side energy and capacity resources.

Section 5 also documents the fact that BC Hydro is dramatically reducing energy conservation (Demand Side Management (DSM)) program spending now and into the future, despite the fact that this is one of the cheapest options available to the utility. Specifically, Site C electricity costs are about three times as much as DSM costs.

Section 6 explores whether or not, and under what conditions, cancelling or suspending the Site C Project would be the least-cost solution going forward. The section begins with a review of the analysis of alternatives undertaken by BC Hydro in its 2013 IRP. Since the time of that analysis, several circumstances have changed. In addition to the collapse in BC Hydro’s load forecast, the cost of the Site C Project has increased $435 million, and the cost of wind resources has declined by about 20% and is projected to decline a further 20% by 2030.

The first analysis evaluates whether the decision in December 2014 to proceed with the Site C Project, with the benefit of over two years’ hindsight, was optimal. This analysis demonstrates that, if the clock could be turned back to December 2014, a Final Investment Decision not to proceed with the Site C Project would have resulted in savings of $1.4 to $1.7 billion.

The subsequent analyses examine the economic implications of continuing, cancelling or suspending the construction of the Site C Project under a number of different scenarios. The findings indicate that cancelling the Site C Project and continuing down an alternative path would save ratepayers $520 to $800 million, depending on the load forecast. In the event that the Site C Project incurs a 25% cost overrun, cancelling the Project would save ratepayers on the order of $1.2 to 1.5 billion, again depending on the load forecast scenario.

The analysis also tests the effects of lower and higher export market prices. If export market prices follow a low scenario, savings from cancelling the Project would increase to $540 to $990 million dollars, depending on the load forecast. With higher than expected market prices, the range of savings from cancelling the Project would fall to $500 to $600 million dollars.

The final analysis considers the implications of suspending as opposed to cancelling the Site C Project, leaving open the possibility of resuming construction if circumstances warrant. Regardless of BC Hydro’s current forecasts of load growth, suspending the Site C Project would save ratepayers $800 to $870 million, depending on the load forecast, compared to completing the Site C Project in F2024. The analysis concludes that suspending the Site C Project is preferable to cancelling the Site C Project, with a potential benefit of up to $350 million dollars.

In summary, our analysis indicates that cancelling the Site C Project as of June 30, 2017 would save between $500 million and $1.65 billion, depending on future conditions, despite the fact that BC Hydro will have incurred on the order of $1.87 billion in costs. Suspending the Site C Project is preferable to cancelling the Project by up to $350 million. All alternative scenarios considered have very low greenhouse gas emissions. Both cancelling and suspending are preferable to continuing with the Site C Project.

www.watergovernance.ca
2. Justification for the Site C Project

2.1 Historical, regulatory and policy context

2.1.1 Two Rivers Policy

The Site C Project follows from a policy first formulated in British Columbia in the 1950s. The Two Rivers Policy called for large-scale hydroelectric development on both the Peace River and Columbia River systems. The result was the development on the Peace River of two projects: the Bennett Dam, including the GM Shrum Generating Station and the Williston Reservoir in 1968, and the Peace Canyon Dam, including the Dinosaur Reservoir, in 1980.

In the early 1980s, BC Hydro applied to the BC Utilities Commission (BCUC) for review of its proposed third project on the Peace River, the Site C Project. The Commission was tasked with reviewing the project’s justification, design, impacts and other relevant matters, and recommending whether and under what conditions an approval should be granted.4

Upon review, the Commission raised a number of “major issues” with respect to the demand forecasts prepared by BC Hydro, as detailed in its report, including:

- forecast methodology;
- the role and forecast of key underlying variables;
- specific factors such as industrial sector growth, technological change, interfuel substitution, conservation and self-generation; and
- prospects and potential in the export market.5

The issues raised by the Commission remain central to the current evaluation of BC Hydro’s forecasted requirements for electrical energy6 and capacity,7 and the suitability of the Site C Project for meeting those requirements.

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6 “Energy” means the amount of electricity delivered or consumed over a certain time period, measured in multiples of watt-hours. A 100-watt bulb consumes 200 watt-hours in two hours.

7 “Capacity” means the power produced or demanded at a particular time, usually measured in kilowatts (kW) or megawatts (MW).
2.1.2 Clean Energy Act

BC Energy Objectives

The *Clean Energy Act* (2010) sets out the framework for assessing the need for electricity to be provided by BC Hydro, and for evaluating the alternatives to meeting that need by establishing energy objectives for British Columbia. These energy objectives include the following:

- to achieve electricity self-sufficiency;
- to take demand-side measures and to conserve energy, including BC Hydro reducing its expected increase in demand for electricity by the year 2020 (F2021)\(^8\) by at least 66%;
- to generate at least 93% of the electricity in British Columbia, other than electricity to serve demand from facilities that liquefy natural gas for export by ship,\(^9\) from clean or renewable resources and to build the infrastructure necessary to transmit that electricity;
- to use and foster the development in British Columbia of innovative technologies that support energy conservation and efficiency and the use of clean or renewable resources;
- to ensure that BC Hydro's rates remain among the most competitive of rates charged by public utilities in North America;
- to reduce BC greenhouse gas emissions as determined under the *Greenhouse Gas Reduction Targets Act*;
- to encourage communities to reduce greenhouse gas emissions and use energy efficiently;
- to reduce waste by encouraging the use of waste heat, biogas and biomass; and
- to achieve British Columbia's energy objectives without the use of nuclear power.

In essence, the *Clean Energy Act* sets a course for reducing greenhouse gas emissions through energy conservation, energy efficiency, and generation of clean (i.e. low-carbon) electricity. It also imposes severe limitations on electricity imports through the self-sufficiency requirement, which includes prohibition on the use of the Canadian Entitlement under the Columbia River Treaty, and prohibits the use of nuclear power. Though not listed among its objectives, the Act also prohibits the development of eleven other potential large-scale hydroelectric projects in the Province.\(^10\)

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\(^8\) BC Hydro conducts its planning on the basis of its fiscal year, which begins on April 1 and ends on March 31. So, for example, the calendar year 2020 is equivalent to the fiscal year 2021, abbreviated as F2021.


\(^10\) *Clean Energy Act*, SBC 2010, c 22, Schedule 2 Prohibited Projects.
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Importantly, the *Clean Energy Act* also sets the objective of maintaining competitively priced electricity, which therefore prioritizes the development of the lowest-cost low-carbon electricity resources. For example, where conservation and energy efficiency (i.e. “demand-side management” or “DSM”) are lower cost, they would take priority over the development of clean or renewable energy, including hydroelectric projects like Site C, wind, biomass, solar and geothermal (i.e. “supply-side resources”).

**Integrated Resource Plan**

In addition to establishing energy objectives, the *Clean Energy Act* also requires BC Hydro to submit, every five years, an integrated resource plan that includes:

- a description of BC Hydro's energy and capacity forecasts; and
- a description of what BC Hydro plans to do to achieve electricity self-sufficiency and to respond to British Columbia's other energy objectives.

BC Hydro prepared and submitted its 2013 IRP in response to these requirements, and the Lieutenant Governor in Council approved the Plan with some modifications on November 25, 2013. The findings and recommendations of the 2013 IRP were used to support the joint federal-provincial environmental assessment of the Site C Project (conducted by the Joint Review Panel or JRP).11

BC Hydro has recently initiated planning and consultation for the 2018 IRP, which is scheduled to be completed by November 2018.

**BCUC exemptions**12

The *Clean Energy Act* exempts several projects, including the Site C Project, from Sections 45 to 47 of the *Utilities Commission Act (UCA)*, removing the requirement for a Certificate of Public Convenience and Necessity (CPCN). By exempting the Project from the need to obtain a CPCN, the *Clean Energy Act* eliminated the process through which the Commission normally reviews the economic and technical justification of a project.

Despite this exemption, the Provincial Cabinet does have further discretion to refer the Site C Project to the Commission in order to address matters that Cabinet considers appropriate, pursuant to Section 5 of the *UCA*.13

Referring large-scale projects such as the Site C Project to the Commission for advice or recommendations, as opposed to binding decisions, formed a key conclusion of the independent review of the BCUC initiated by the Minister of Energy in November

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12 See also UBC Program on Water Governance. 2016. Briefing Note #3: The Regulatory Process for the Site C Project, S.3.2.4, (Available at: www.waterpartners.ca/projects/sitec)

Reassessing the Need for Site C

2013. This review, completed before the final decision to proceed with the Site C Project, reiterated on several occasions the benefits of referring large-scale projects to the BCUC for review and recommendations.

This provides the benefit of a public process and independent verification of projects and plans but reserves the final decision on plans and projects that have broader public interest criteria to be decided by elected officials.

Broader use of section 5 is similar to the approach taken by the Federal government in its recent amendments to the National Energy Board Act. These amendments redefined the role of the Board, which is now mandated not to decide on applications for pipeline certificates, but to instead make a recommendation to the Federal Cabinet.

2.1.3 Climate Leadership Plan

Released in August 2016, following approval of the Site C Project, the Climate Leadership Plan sets out a number of actions designed to support BC’s climate change policy objectives. These actions include:

• supply 100% of electricity for the integrated grid from clean or renewable sources, except where concerns regarding reliability or costs must be addressed;
• electrification of natural gas production, processing and transmission, all currently fuelled by natural gas and diesel fuel, to reduce greenhouse gas emissions;
• expanding the mandate of BC Hydro’s DSM programs to include investments that increase efficiency and reduce GHG emissions;
• expanding the Clean Energy Vehicle Program; and
• amending the energy efficiency standards regulation.

These actions will have implications for future requirements for low-carbon electricity that were not contemplated at the time of the decision to proceed with the Site C Project in 2014. They are therefore relevant to any determination of whether to continue the Site C Project to completion as scheduled, cancel the project, or suspend the project leaving open the possibility of continuing the project if future circumstances warrant.

16 Unless stated otherwise, all underlining of quotations in this report is emphasis added by this report’s authors.
2.1.4 Environmental assessment

In August 2011, the provincial and federal governments commenced environmental assessment of the Site C Project pursuant to the BC Environmental Assessment Act and the Canadian Environmental Assessment Act, 2012 (CEAA). To avoid duplication of effort, the two levels of government collaborated in the development of a Joint Review Panel Agreement, establishing an independent three-person Joint Review Panel (JRP) to review and report to the Ministers respecting the matters detailed in the JRP Terms of Reference and the Environmental Impact Statement (EIS) Guidelines, incorporated into the Agreement.

The EIS Guidelines for the conduct of the environmental assessment required that the EIS:

- provide the fundamental rationale for proceeding with the development at this time within the relevant legal and policy context;
- describe the functionally different ways to meet the need for the Project;
- contain an analysis of technically and economically feasible alternatives to the Project; and
- complete that analysis to a level of detail sufficient to compare the proposed project with its alternatives.18

In its submissions before the JRP, BC Hydro stated that the purpose of the Site C Project is to cost-effectively meet BC Hydro’s forecasted need for energy and capacity.19 Thus, the forecasting of those needs and the cost-effectiveness of the alternatives was a key consideration during the review.

BC Hydro also presented information during the environmental assessment concerning the GHG emissions from the Site C Project. These emissions from both construction and operations total 5.5 MT CO2e by 2034, 6.0 MT CO2e by 2054, and 6.8 MT by 2124, 100 years following commissioning.20

On a per unit energy basis the Site C Project delivers both energy and capacity with very low GHG emissions, which is a key advantage of the Project. But these emissions are not zero, and other alternatives also deliver energy and capacity with very low GHG emissions.21

The JRP concluded in its final report issued in May 2014 that the Site C Project would likely result in an unprecedented number of significant adverse environmental effects, including in relation to First Nation use of lands and resources for fishing, hunting and trapping.22 A determination of significant adverse environmental effects is uncommon, and has occurred for only 12 of over 120 major projects assessed since the coming into force of the CEAA in 1995, as summarized below Table 1. As this table illustrates, the number of significant adverse environmental effects determined by the JRP is far beyond that which was concluded for any other project ever assessed under the CEAA.

The numerous adverse environmental effects of the Site C Project represent a key disadvantage of the Project. While the alternatives to the Site C Project would also have environmental effects, it is very unlikely that any of these effects would be significant.23

The JRP also reached conclusions and made recommendations to the Ministers respecting several matters concerning the need for the Site C Project, most importantly that BC Hydro had not fully demonstrated the need for the Project on the proposed timetable, namely for an in-service date of F2024. As a result of this and other conclusions, the JRP recommended referral of key matters to the BC Utilities Commission for further review, including the costs of the Site C Project, the load forecast, long-term electricity prices, and the demand-side management plan.24

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21 For a comparison of the GHG emissions of the Site C Project and these alternatives, see: Hendriks, R.M. July 2016. Comparative Analysis of Greenhouse Gas Emissions of Site C versus Alternatives. UBC Program on Water Governance. (Available at: www.waterpartners.ca/projects/sitec)


23 For a comparison of the environmental effects of the Site C Project and these alternatives, see: UBC Program on Water Governance. 2016. Briefing Note #2: Assessing Alternatives to Site C: Environmental Effects Comparison, (Available at www.waterpartners.ca/projects/sitec)

Table 1: Significant adverse environmental effects under the *CEAA*\textsuperscript{25}

<table>
<thead>
<tr>
<th>Project</th>
<th>Number of Significant Effects</th>
</tr>
</thead>
<tbody>
<tr>
<td>Site C Clean Energy Project</td>
<td>20</td>
</tr>
<tr>
<td>New Prosperity Gold and Copper Mine Project</td>
<td>5</td>
</tr>
<tr>
<td>Lower Churchill Hydroelectric Generation Project</td>
<td>5</td>
</tr>
<tr>
<td>Pacific Northwest LNG\textsuperscript{26}</td>
<td>3</td>
</tr>
<tr>
<td>Encana Shallow Gas Infill Development Project</td>
<td>2</td>
</tr>
<tr>
<td>Cheviot Coal Project</td>
<td>2</td>
</tr>
<tr>
<td>Kemess North</td>
<td>2</td>
</tr>
<tr>
<td>Northern Gateway Project</td>
<td>1</td>
</tr>
<tr>
<td>White Pines Quarry</td>
<td>1</td>
</tr>
<tr>
<td>LNG Canada</td>
<td>1</td>
</tr>
<tr>
<td>Labrador-Island Transmission Link</td>
<td>1</td>
</tr>
</tbody>
</table>

\textbf{2.2 Approval of the Site C Project}

\textbf{2.2.1 Environmental assessment decisions}

In October 2014, following a period for review and consultation on the final report issued by the JRP, both the provincial and federal governments issued their environmental assessment decisions.

In its decision, the Government of Canada agreed that the Site C Project was likely to cause significant adverse environmental effects under *CEAA 2012*, but that these significant adverse environmental effects were justified in the circumstances.\textsuperscript{27} In making these determinations, the federal government provided no information respecting the framework for its justification process, no description of the contextual circumstances, no responses to the recommendations from the JRP, and no reasons for its decision.

The Provincial Government, through the BC Environmental Assessment Office (EAO) issued an Environmental Assessment Certificate to BC Hydro in relation to the Site C Project in October 2014. This approval was accompanied by a response from the Executive Director of the EAO to the recommendations of the JRP. With respect to the

\textsuperscript{25} For details concerning the nature of the significant adverse environmental effects, see: UBC Program on Water Governance. 2016. Briefing Note #2: Assessing Alternatives to Site C: Environmental Effects Comparison, Table 2.1 and Table 2.2. (Available at www.waterpartners.ca/projects/sitec)


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JRP recommendations to refer key matters to the BC Utilities Commission for further review, the EAO did not accept them, deeming these matters to be “outside of the scope of the Panel’s mandate.” No further action has been taken to date by the Provincial Government in relation to these recommendations.

2.2.2 Final Investment Decision (FID)

As the sole shareholder and owner of BC Hydro, the Provincial Government had the responsibility for deciding whether or not to initiate the Site C Project. In announcing its decision to authorize development of the Site C Project in December 2014, the Province stated that:

…[Site C would] provide British Columbia with the most affordable, reliable clean power for over 100 years.29

This observation provides insight into the process used by the Provincial Government in making the decision to proceed with the Site C Project in the face of the Project’s many significant adverse environmental effects, and implications for First Nations rights.30 More recently, the Provincial Minister of Energy and Mines stated the following:

The [Site C] hydroelectric project will deliver the lowest-cost, cleanest power available,” the minister said, although he conceded it would have adverse environmental impacts … .31

As noted above in Section 2.1.4, the JRP concluded that the Site C Project would likely result in an unprecedented number of significant adverse environmental effects, including in relation to First Nation use of lands and resources for fishing, hunting and trapping. Thus the significant adverse environmental effects of the Site C Project were justified by government based on the premise that the Project will deliver energy and capacity at lower GHG emissions and lower costs than the available alternatives.

The following sections of this report explore these claims in the context of the information publicly available at the time the decision was made to proceed with the Site C Project, as well as information that has become available since that time.

29 Government of British Columbia. December 16, 2014. “Site C to provide more than 100 years of affordable, reliable clean power”. (Accessed 17 April 2017 at https://news.gov.bc.ca/stories/site-c-to-provide-more-than-100-years-of-affordable-reliable-clean-power)
30 UBC Program on Water Governance. 2016. Briefing Note #1: First Nations and Site C. (Available at: www.waterpartners.ca/projects/sitec)
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3. Revisiting future electricity needs

3.1 Evolution of future electricity requirements

This Section 3 focuses on the evolution of BC Hydro’s future domestic electricity requirements, which are a key consideration in evaluating the need for the Site C Project. Section 3.2 extensively reviews BC Hydro’s historical load forecasts, recently filed with the BCUC, demonstrating the utility’s consistent overestimating of actual future requirements. Section 3.3 explores the dramatic decline in BC Hydro’s most recent 2016 Load Forecast compared to the 2012 Load Forecast used to justify the Site C Project. Section 3.4 explores the potential that low-carbon electrification, as a means to reduce greenhouse gas emissions, could advance requirements for electricity. A summary of the findings is provided in Section 3.5.

Throughout its planning, assessment and promotional documentation, BC Hydro framed the need for the Site C Project as follows:

Site C is required to meet the long-term energy and capacity needs of BC Hydro’s residential, commercial and industrial customers. BC Hydro forecasts that the province’s electricity needs will grow by approximately 40 per cent over the next 20 years, not accounting for savings that can be achieved through conservation and efficiency measures.32

The purpose of the Site C Project, as proposed by BC Hydro, is to meet British Columbia’s domestic electricity requirements. The Site C Project is not an export project designed to meet requirements of other jurisdictions in the United States or Canada.

The justification for proceeding with the Site C Project at this time hinges on BC Hydro’s forecast that the province’s electricity needs will grow by 40% over the next 20 years. Importantly, this is before accounting for energy savings from conservation and efficiency (i.e. DSM). After accounting for DSM, BC Hydro’s most recent forecast projects that electricity needs will grow by only 30%,33 meaning that BC Hydro is projecting that DSM will play only a modest role in reducing future electricity requirements. This is surprising since BC Hydro currently projects that DSM will meet more than 100% of the utility’s needs to F2021, even if the utility were to immediately and entirely discontinue future spending on DSM programs.34 This issue of the fate of DSM continues to receive close scrutiny.

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DSM is considered in greater detail in section 5.3.1. Here, the first task is to consider the accuracy of BC Hydro’s historical forecasts.

### 3.2 BC Hydro’s historical load forecasts of domestic requirements

#### 3.2.1 The factors affecting load forecasting

BC Hydro’s future domestic requirements for electrical energy and capacity are inherently uncertain. The rate of growth (stagnation or contraction) in these requirements can be influenced by multiple, highly variable factors, including the following:

- rates of economic and income growth;
- population growth and residential sector consumption growth;
- commercial sector growth;
- industrial sector growth;
- shifts in the economy towards services, which generally consume less energy;
- the cost of energy from alternative energy sources, including the influence of carbon pricing, and cross-price elasticity effects on electricity demand;
- the price of electricity and own-price elasticity effects on electricity demand;
- the use of on-site electricity or alternative energy supply resources that reduce requirements for electricity from the interconnected grid;
- demand-side management, including technological evolution and costs; and
- the extent of low-carbon electrification to reduce greenhouse gas emissions.

Considering these multiple highly variable factors, no forecast will be entirely accurate at projecting requirements, particularly many years into the future. Forecasts that are too low may result in energy or capacity shortfalls that trigger additional costs to import or operate more costly generation during peak demand periods or, in extreme circumstances, have implications for system reliability. However, forecasts that are too high may result in advancing supply-side resources prior to actual needs, resulting in additional and unnecessary costs to ratepayers when surplus energy must be sold at prices below the costs of production.

Utilities rightly treat these risks asymmetrically, since underestimating future requirements involves a risk to reliability that overestimating does not. Thus, BC Hydro builds a number of additional factors into its energy and capacity forecasting, including the following:

- a capacity reserve equal to 14% of supply;
- the potential for additional market reliance;
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- the potential to make use of energy and capacity from the Canadian Entitlement under the Columbia River Treaty;35
- the potential for capacity-focused DSM and additional load-shedding; and
- planned renewal of only 50% of biomass EPAs and 75% of run-of-river hydroelectric EPAs.

These measures are designed to address this asymmetry of risk. However, it is not good utility practice to overforecast in order to reduce these risks. Indeed, in the JRP hearings for the Site C Project, BC Hydro declared that good forecasting entails predictions that are wrong as much in one direction as in the other.

Mr. David Ince [BC Hydro Manager of Market Forecasting]: One of the key principles of the forecast is that we try not to bias it. So it’s a P50 forecast. That’s what we endeavour for. So, hopefully, my legacy will be that 20 years from now… that 50 percent of the time, my forecasts would have been too high and 50 percent too low, so with no intention of bias.36

However, a review of past BC Hydro load forecasts demonstrates that this has not been the case.

3.2.2 “Optimistic” load forecasting

In response to recent BCUC concerns respecting whether this pattern “is an indication of a statistical bias, accurate forecasting issues and/or a random occurrence”,37 BC Hydro recently filed its load forecasts from 1964 to 2016 with the Commission, along with data showing actual electrical energy requirements over that same period.38

Since 1981, BC Hydro has prepared 36 load forecasts, including a total of 553 estimates of future energy requirements in specific future years. If BC Hydro’s approach were unbiased, then half of these projections would be overestimates and half underestimates. BC Hydro’s data reveal, though, that 85% of these projections were overestimates. Since Site C was initially proposed in the early 1980s, BC Hydro’s load forecasts have consistently overstated future growth in electricity requirements.

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35 See Section 5.4.2 below.
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Since 1992, when BC Hydro began producing annual forecasts, 89.5% of the utility’s mid-load projections were overestimates. These estimates in fact could be better described as a high-load forecast, defined as a forecast that is expected to exceed actual future requirements 90% of the time. 39

In its submissions to the BCUC in support of the Site C Project in 1981, BC Hydro’s “probable” or “mid-load” forecast predicted that system-wide energy demand would increase from 31,450 GWh/year in F1981 to 90,000 GWh by F2002, net of conservation.40 This load forecast is presented in Figure 1 below.

Figure 1: BC Hydro’s F1981 Load Forecast (after DSM)41

The overestimation of future requirements is dramatic. In fact, even the 60,500 GWh forecast for F1992, when BC Hydro proposed to commission the Site C Project, has yet to be reached twenty-five years later. In BC Hydro’s most-recent forecast contained in

39 Or to state this another way, the high-load forecast has a probability of being exceeded by actual requirements 10% of the time.
its 2016 RRA, the utility forecasts that integrated system requirements net of planned DSM are now expected not to exceed this value until F2023, or more than thirty years later than initially forecast in 1981.

The Commission concluded at that time that: “Hydro’s ‘probable’ load forecast should be considered as optimistic” and recommended that the provincial Cabinet:

…the defer issuing an Energy Project Certificate for Site C until an acceptable load forecast demonstrates that construction of Site C must begin immediately in order to avoid supply deficiencies, and a comparison of alternative system plans demonstrates that Site C is the best project to meet the anticipated shortfalls.

As discussed below, BC Hydro’s tendency toward overly “optimistic” load forecasts has continued to the present.

3.2.3 F1992 to F2008 load forecasts

In 1992, BC Hydro began its current practice of producing 20-year forecasts of future energy requirements. Figure 2 illustrates BC Hydro’s forecasts of future energy requirements after DSM against actual requirements for the F1992 through F1999 and F2000 through F2008 periods, respectively.

The forecasts from F1992 through F1999 all overstated actual requirements from F2001 through F2008 (the dark "Actuals" line), and drastically overstated actuals for the period since the 2008-2009 recession. The F1992 through F1995 load forecasts all overstate demand 20 years later by on the order of 11,000 to 18,000 GWh/year. With respect to current requirements, in its 2016 RRA, BC Hydro reported total gross system requirements of 55,674 GWh in F2016, meaning that the utility’s forecasts from 1996 through 1999 overstated current requirements by 14,000 to 18,000 GWh/year. This is about three times the average annual generation of the Site C Project (5,100 GWh/year).

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Figure 2: BC Hydro forecasts of total gross requirements\textsuperscript{46}, after DSM

a) F1992 to F1999

\[
\begin{align*}
\text{Actual} & \quad 60,000 & 61,000 & 62,000 & 63,000 & 64,000 & 65,000 & 66,000 & 67,000 & 68,000 & 69,000 & 70,000 & 71,000 & 72,000 & 73,000 & 74,000 & 75,000 & 76,000 \\
F1992 & \quad 60,000 & 61,000 & 62,000 & 63,000 & 64,000 & 65,000 & 66,000 & 67,000 & 68,000 & 69,000 & 70,000 & 71,000 & 72,000 & 73,000 & 74,000 & 75,000 & 76,000 \\
F1993 & \quad 60,000 & 61,000 & 62,000 & 63,000 & 64,000 & 65,000 & 66,000 & 67,000 & 68,000 & 69,000 & 70,000 & 71,000 & 72,000 & 73,000 & 74,000 & 75,000 & 76,000 \\
F1994 & \quad 60,000 & 61,000 & 62,000 & 63,000 & 64,000 & 65,000 & 66,000 & 67,000 & 68,000 & 69,000 & 70,000 & 71,000 & 72,000 & 73,000 & 74,000 & 75,000 & 76,000 \\
F1995 & \quad 60,000 & 61,000 & 62,000 & 63,000 & 64,000 & 65,000 & 66,000 & 67,000 & 68,000 & 69,000 & 70,000 & 71,000 & 72,000 & 73,000 & 74,000 & 75,000 & 76,000 \\
F1996 & \quad 60,000 & 61,000 & 62,000 & 63,000 & 64,000 & 65,000 & 66,000 & 67,000 & 68,000 & 69,000 & 70,000 & 71,000 & 72,000 & 73,000 & 74,000 & 75,000 & 76,000 \\
F1997 & \quad 60,000 & 61,000 & 62,000 & 63,000 & 64,000 & 65,000 & 66,000 & 67,000 & 68,000 & 69,000 & 70,000 & 71,000 & 72,000 & 73,000 & 74,000 & 75,000 & 76,000 \\
F1998 & \quad 60,000 & 61,000 & 62,000 & 63,000 & 64,000 & 65,000 & 66,000 & 67,000 & 68,000 & 69,000 & 70,000 & 71,000 & 72,000 & 73,000 & 74,000 & 75,000 & 76,000 \\
F1999 & \quad 60,000 & 61,000 & 62,000 & 63,000 & 64,000 & 65,000 & 66,000 & 67,000 & 68,000 & 69,000 & 70,000 & 71,000 & 72,000 & 73,000 & 74,000 & 75,000 & 76,000 \\
\end{align*}
\]

b) F2000 to F2008

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Total gross system requirements include: sales to the residential, commercial and industrial customer classes plus sales to other utilities, and adjusted for system line losses. To determine gross energy requirements for only the integrated system, sales and line losses to all non-integrated areas are excluded.
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BC Hydro’s projections from F2000 to F2005 were more consistent with actual requirements, but only within the first few years of the forecast period. None of the forecasts appears to have contemplated the potential for a recession in the 20-year forecast period. This despite the acknowledgement by BC Hydro that there have been six recessionary periods, or about one per decade, for the period of readily available data dating to 1964. The forecasts from F2000 through F2008 overstate current requirements by 6,500 to 11,500 GWh/year (one to two times the annual generation of the Site C Project).

3.2.4 F2009 to F2016 load forecasts

In its responses filed for the 2016 RRA, BC Hydro notes that since F2010: “total domestic temperature adjusted billed sales has increased in total by 1,421 GWh or 2.8 percent”. While this is true, it fails to acknowledge the overall decline in the years 2007 to 2016, as illustrated in Figure 3.

Figure 3: Total domestic temperature adjusted billed sales – F2007 to F2016

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Furthermore, this is not indicative of a longer-term growth trend; particularly since temperature adjusted billed sales in F2016 were actually lower than they were in F2014. The evidence is insufficient to draw conclusions about the average rate of growth (stagnation or contraction) going forward from the 2008-2009 recession.

Figure 3 demonstrates that actual domestic billed energy sales in F2016 were 51,861 GWh/year, less than they were a decade earlier. Indeed, domestic energy sales are now projected by BC Hydro not to exceed those of F2007 until at least F2020 under its mid-load forecast. The stability in BC Hydro’s domestic energy sales over the past decade is presented in Figure 4, which illustrates that domestic energy sales have remained between 48,000 and 52,000 GWh/year since F2004.

Though BC Hydro’s load forecasts have consistently anticipated growth in its domestic energy requirements, that growth has not materialized, which explains the recent comments of the Minister of Energy and Mines, Bill Bennett.

British Columbia’s electricity requirements this year are the same as they were eight years ago, a trend that means new clean-energy capacity is not a priority.

50 The difference of 10,159 GWh between the total domestic energy sales before DSM of 62,987 GWh in F2017 and the actual domestic sales now projected to be 51,860 GWh in F2017 illustrates the substantial role that DSM plays in meeting BC Hydro’s domestic requirements.
52 Domestic energy sales include residential, light industrial and commercial, large industrial and here excludes “other energy sales”. Since 2012, BC Hydro began to include surplus energy sales in “other energy sales”, and removing this category allows comparisons across the entire 20-year period, and more accurately reflects the evolution of domestic requirements over time.
Figure 5a) presents BC Hydro's forecasts for the five years following the 2008-2009 recession. As with prior forecasts, these forecasts also predicted future requirements that are higher than actuals. However, the variability in the forecasts increased substantially over prior forecasts. The pattern in the variability of these forecasts raises potentially disturbing questions.

Comparing the charts in Figure 2 to Figure 5a) illustrates this unusual pattern. In Figure 2, the long-term predicted energy requirements vary between forecasts on the order of 6,000 GWh/year, while in Figure 5a) they vary by more than 15,000 GWh/year.

Figure 5a) illustrates that, from 2009 through 2013, BC Hydro’s load forecast increased markedly. Using forecast loads for F2024 as an index, the load forecast increased by about 3,000 GWh/year in 2010 and 2011, by 5,000 GWh/year in 2012, and by 8,000 GWh/year in 2013. The forecasts of energy requirements in F2024, when the Site C Project is due to be commissioned, vary from 60,592 GWh/year in the F2009 Load Forecast to 78,134 GWh/year in the F2013 Load Forecast, a difference of nearly 18,000 GWh/year – more than three times the annual generation of Site C.

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54 BC Hydro. Annual Reports. (Accessed 17 April 2017 at: https://www.bchydro.com/about/accountability_reports/financial_reports/annual_reports.html)
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Figure 5b) presents BC Hydro’s forecasts for the years 2013-2016. It shows that BC Hydro’s load forecast for F2024 fell just as quickly as it had increased – by 8,000 GWh/year in 2014, and by another 2,000 GWh/year in each of 2015 and 2016.

Figure 5: BC Hydro forecasts of total gross requirements after DSM

a) F2009 to F2013

b) F2013 to F2016
This pattern in the load forecasts for F2024 can be seen in Figure 6. In F2009, prior to the decision on the part of the Provincial Government and BC Hydro to commence the environmental assessment of the Site C Project, the forecasted requirements for F2024 were barely higher than actuals in F2009. There was no forecasted load growth that would justify developing the Site C Project.

Following the decision in 2010 to proceed with the environmental assessment of the Site C Project, the forecasted requirements for F2024 increased dramatically by 18,000 GWh/year leading up to the decision to approve the Project.

Then, following the approval in F2014, the load forecasts steadily declined with projections for requirements in F2024 nearly 15,000 GWh/year lower in the F2016 Load Forecast than they were just three years earlier.

These changes in the load forecast were not reflected by any change in the actual loads, which remained flat through this entire period. This collapse in BC Hydro’s load forecast is considered further below in Section 3.3.

Figure 6: Forecasted total gross requirements (after DSM) in F2024

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This pattern could be seen as a reflection of the substantially increased level of uncertainty in future requirements, and of the challenges that BC Hydro is having modeling that uncertainty. However, the pattern also raises questions about whether BC Hydro’s load forecasting was “strategically optimistic” in order to support a favourable decision by government to develop the Site C Project.

3.2.5 Load forecasting summary

Since the F1981 Load Forecast prepared by BC Hydro to support the development of the Site C Project, the utility has prepared a total of 35 load forecasts of 10 years or longer. Figure 7 compares BC Hydro’s forecasts against actuals 10 years later.

As illustrated in this figure, BC Hydro’s forecasters have overestimated 10-year future requirements on all but 3 of 25 occasions, and for 19 years in a row. On average, BC Hydro’s load forecasts overestimate actual requirements 10 years later by 9.1%. For the most recent 19 load forecasts for which 10-year comparisons can be made, this overestimation rises to an average of 9.7% above actuals, or 5,443 GWh/year.56

Figure 7: BC Hydro load forecasting overestimates – 10 years after forecast

Figure 8 compares BC Hydro’s forecasts against actuals 15 years later. All of these forecasts substantially overestimated future requirements 15 years later, on average by more than 15% or 9,254 GWh/year.57

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56 Not shown in Figure 7.
57 A load forecast was not available for F1991, and so no comparison 10 years later could be made.
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Figure 8: BC Hydro load forecasting overestimates – 15 years after forecast

Similarly, Figure 9 compares BC Hydro’s forecasts against actuals 20 years later. Once again, all five of BC Hydro’s 20-year forecasts exceed actual requirements 20 years later by an average of more than 25% or 14,445 GWh/year.

Figure 9: BC Hydro load forecasting overestimates – 20 years after forecast
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The previous three figures illustrate that **as time passes, BC Hydro’s forecasts become more and more inaccurate.** During the environmental assessment hearings for the Site C Project, two factors affecting the load forecast were considered at some length: the price elasticity of demand for electricity and the role of the 2008-2009 recession.

Price elasticity is the degree to which consumers reduce electricity consumption in response to increasing price.\(^\text{58}\) BC Hydro uses a value of -0.05 to reflect rate-increase induced savings over the short and long-term for all customer classes.\(^\text{59}\) This value is far lower than the average values cited in the regional studies summarized in Table 2.

### Table 2: Price elasticity of electricity demand – literature values

<table>
<thead>
<tr>
<th>Customer Class</th>
<th>Reference</th>
<th>Short-run</th>
<th>Long-run</th>
</tr>
</thead>
<tbody>
<tr>
<td>Residential</td>
<td>Paul, Myers and Palmer(^\text{60})</td>
<td>-0.13 (-0.05 to -0.32)(^\text{61})</td>
<td>-0.40 (-0.14 to -1.16)</td>
</tr>
<tr>
<td></td>
<td>Bernstein and Griffin(^\text{62})</td>
<td>-0.24</td>
<td>-0.32</td>
</tr>
<tr>
<td>Commercial</td>
<td>Paul, Myers and Palmer</td>
<td>-0.11 (-0.01 to -0.22)</td>
<td>-0.29 (-0.02 to -0.70)</td>
</tr>
<tr>
<td></td>
<td>Bernstein and Griffin</td>
<td>-0.21</td>
<td>-0.97</td>
</tr>
<tr>
<td>Industrial</td>
<td>Paul, Myers and Palmer</td>
<td>-0.16 (-0.08 to -0.31)</td>
<td>-0.40 (-0.20 to -0.82)</td>
</tr>
</tbody>
</table>

As shown in the table, price elasticity varies substantially across regions, though overall values are quite consistent between the studies.\(^\text{63}\) BC Hydro’s determination of price elasticity is at the very low end of the short-run elasticity determined in the studies reviewed. This is relevant considering the substantial real increase in electricity rates in the 10-Year Rates Plan —on the order of 19% real (46% nominal).\(^\text{64}\) Given these significant rate increases to come, BC Hydro’s low estimate of price elasticity may lead it to overestimate future requirements.

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\(^{58}\) This is distinct from the effect of rates specifically designed to reduce consumption (e.g. the residential inclining block rate) and the effect of DSM programs, codes and standards.

\(^{59}\) BC Hydro. December 9, 2013. Site C Clean Energy Project. Undertaking No.1. (Accessed 17 April 17 at: [http://www.ceaa-acee.gc.ca/050/documents/p63919/97058E.pdf](http://www.ceaa-acee.gc.ca/050/documents/p63919/97058E.pdf)). This means that, for every 1% increase in price, consumption is expected to decline by 0.05%.


\(^{61}\) Bracketed values indicate ranges across different regions.


\(^{63}\) Some variability is expected given regional differences in infrastructure, consumer preferences, local economic activity, and seasonality, among other factors.

\(^{64}\) Government of BC. November 26, 2013. 10 Year Plan for BC Hydro, p.32. Available at: [https://news.gov.bc.ca/stories/10-year-plan](https://news.gov.bc.ca/stories/10-year-plan)
Importantly, the studies show that long-run price elasticity is much higher than short-run elasticity in all three sectors. This suggests that over the longer-term, consumers are much more responsive to changes in electricity prices, opting to consume less electricity through conservation, fuel switching and equipment replacement.

With respect to the 2008-2009 recession, it appears that BC Hydro’s testimony in the environmental assessment hearings exaggerated the role of the recession with regard to the accuracy of its load forecasting, when it said:

So I would suggest the 2008/2009 recession, and how it persisted for many years, in an almost unexpected fashion, caught every forecaster by surprise whether it be the Forecasting Council of BC, who we get advice from, or the banks. It was really an unprecedented event in terms of the duration of it. ... And I think for the first time we’re starting to see some stability in terms of recovery. And so we do have modest load growth considered in our forecast .... 65

The 2008-2009 recession may explain, in part, BC Hydro’s substantial overestimates of future energy requirements in the years thereafter, as shown in Figure 9. However, it cannot explain the overestimates in the years prior to the recession, as shown in Figure 7 and Figure 8. Nor can it explain the overestimate of requirements in load forecasts made since the recession, including those used to support launching the Site C Project. Was BC Hydro’s expected “modest load growth” since the 2008-2009 recession, noted above, also “optimistic”? Events since the 2013 IRP, described in the following section, suggest that it was.

A detailed exploration of the multiple and highly variable factors listed in Section 3.2.1 that could more fully explain BC Hydro’s consistent overestimation of actual requirements over the past 35 years is beyond the scope of this report. Those factors are best investigated by the BC Utilities Commission, which has the capacity to review them through a rigorous public process accessible to interveners and experts.

3.3 Collapse of BC Hydro’s 2012 Load Forecast

3.3.1 BC Hydro’s 2013 IRP

BC Hydro’s 2012 Load Forecast forms the basis for the 2013 IRP, which was accepted by the Provincial Government and used to support the approval of the Site C Project. In that planning process, BC Hydro prepared load-resource balances for energy and capacity reflecting the differences between supply and demand, before and after DSM. These “LRBs”, as presented in the final November 2013 IRP, are shown in Figure 10.

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Figure 10: 2013 IRP base resource plans with expected LNG

a) Capacity

b) Energy
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The charts illustrate that, in the 2013 base resource plan under the “Expected LNG” scenario, BC Hydro saw the need for new resources as follows:

- Before DSM:
  - additional capacity resources would be required in F2016
  - additional energy resources would be required in F2017
- After DSM:
  - additional capacity resources would be required in F2019
  - additional energy resources would be required in F2022

On the basis of these forecast requirements, the Site C Project was planned for addition to the supply mix in F2024. Considering that capacity resources were anticipated to be required by F2019, the capacity load-resource balance also reflects BC Hydro’s intention (at that time) to develop 400 MW of simple-cycle gas turbines (SCGTs) beginning in F2020, in order to supply expected additional liquefied natural gas (LNG) electric load requirements, and to make use of market purchases (or capacity from the Columbia River Treaty Entitlement) as “bridging resources” prior to the Site C Project coming into service.

The charts also illustrate that, in the absence of DSM, BC Hydro predicted (in 2013) both a capacity and an energy shortage by F2016, indicating the pivotal role that DSM plays in meeting requirements. These anticipated shortages did not materialize, as there has been no net increase in demand since 2007. In other words, BC Hydro’s additional domestic needs since 2008 have been met entirely with DSM.

3.3.2 BC Hydro’s 2016 Revenue Requirements Application

On July 28, 2016, BC Hydro filed its Fiscal 2017 to Fiscal 2019 Revenue Requirements Application with the BC Utilities Commission. This Application provides the first meaningful update of BC Hydro’s forecasted energy and capacity requirements since the 2013 IRP.

BC Hydro’s updated load-resource balances, reflecting the differences between supply and demand, before and after DSM, are shown in Figure 11. These charts indicate

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66 The base resource plan is the “mid-level forecast” for the purposes of the Electricity Self-Sufficiency Regulation, BC Reg. 315/2010.
67 BC Hydro estimated that future requirements of the LNG industry could range from 800 to 6,600 GWh/year of energy and 100 to 800 MW of capacity, with an Expected LNG load of 3,000 GWh/year and 360 MW by F2022.
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that, in the base resource plan,\(^7\) BC Hydro saw the need (in 2016) for new resources as follows:

- **Before DSM:**
  - additional capacity resources would be required in F2020
  - additional energy resources would be required in F2022\(^7\)

- **After DSM:**
  - additional capacity resources would be required in F2023
  - additional energy resources would be required in F2025\(^7\)

The updated LRBs display a substantial deferral of the need for new resources, compared to the 2013 IRP. Table 3 summarizes the changes in BC Hydro’s forecasts of its electricity requirements over the three-year period between the 2013 IRP and the 2016 RRA. **The table demonstrates that, in every case, the need date has shifted several years into the future since the 2013 IRP.**

**Table 3: Deferred domestic electricity requirements**

<table>
<thead>
<tr>
<th></th>
<th>Need Date</th>
<th>Time Deferred</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>2013 IRP</td>
<td>2016 RRA</td>
</tr>
<tr>
<td><strong>Capacity (before DSM)</strong></td>
<td>F2016</td>
<td>F2020</td>
</tr>
<tr>
<td><strong>Capacity (after DSM)</strong></td>
<td>F2019</td>
<td>F2023</td>
</tr>
<tr>
<td><strong>Energy (before DSM)</strong></td>
<td>F2017</td>
<td>F2022</td>
</tr>
<tr>
<td><strong>Energy (after DSM)</strong></td>
<td>F2022</td>
<td>F2025</td>
</tr>
</tbody>
</table>

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\(^7\) The base resource plan in the 2016 RRA includes the expected LNG of 2,848 GWh/year and 361 MW.


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Figure 11: 2016 RRA unbalanced base resource plans with expected LNG

a) Capacity

b) Energy
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The differences between the two load forecasts are shown more clearly in Figure 12. As illustrated, the requirement for energy in the 2016 Load Forecast is substantially lower than in the 2012 Load Forecast used to justify proceeding with the Site C Project.

**Figure 12: 2012 Load Forecast versus 2016 Load Forecast, after DSM**

![Graph showing load forecasts](image)

Throughout the 20-year forecasting period, the difference is on the order of 5,000 GWh/year of energy. **In other words, in the four years since the 2012 Load Forecast, a “requirement” for energy equivalent to the Site C Project has disappeared from BC Hydro’s 2016 Load Forecast.** The expectation in the 2012 Load Forecast that energy requirements after DSM would reach 70,000 GWh/year by F2024, when Site C would be commissioned, is now expected in the 2016 Load Forecast not to occur until F2032, eight years later.

As also shown in Figure 12, **actual requirements in F2016 are 6,500 GWh/year less than predicted just four years earlier in F2012.** This illustrates that BC Hydro’s mid-load forecasts continue to substantially overestimate actual future requirements.

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3.3.3 Implications of overestimating requirements

As shown above in Table 3, the requirement for energy (after DSM, including expected loads from LNG) has been deferred from F2022 to F2025, which is after the F2024 in-service date for the Site C Project. **This means that, based on BC Hydro’s mid-load forecast in the 2016 RRA, energy from the Site C Project will be entirely surplus when the Project comes on-line beginning in December 2023.**⁷⁴ In the event that load growth continues to underperform BC Hydro’s load forecasts, the dates of requirements for capacity and energy after DSM could be deferred much later.

**In other words, the current situation facing BC Hydro is very different from the one evaluated in the 2013 IRP, upon which was based the decision to proceed with the Site C Project with a planned completion date of F2024.**

The potential for load to be higher than the mid-load forecast is modeled by BC Hydro in its “large gap” scenario. This scenario is based on higher than expected demand combined with lower DSM delivery and lower than anticipated load carrying capacity of clean resources (i.e. low hydroelectric reservoir inflows, less wind, etc.).⁷⁵ Under such a scenario, the need for new capacity advances from F2023 to F2019 and bridging resources (potentially including simple-cycle gas turbines, imports, or short-term use of the Canadian Entitlement under the Columbia River Treaty) would be advanced until the Site C Project entered operations. However, a high-load scenario now appears exceedingly unlikely, considering continuing delays and uncertainties related to several mining, LNG, and oil and gas projects, reduced potential new mining and oil and gas loads resulting from low commodity prices, and lower than expected housing starts and hence lower residential and commercial demand for electricity.⁷⁶

BC Hydro also considers the potential for load to be much lower than the mid-load forecast, which BC Hydro models in its “small gap scenario”. In this scenario, the **energy from the Site C Project (if commissioned in F2024 as currently planned) would be entirely surplus until F2036, and so would inevitably remain substantially surplus well beyond the end of the 20-year planning period.** The implications of the prolonged energy surplus that would be created by developing the Site C Project under the low-load forecast are discussed further below in Section 4.4.2.

Since the release of BC Hydro’s 2016 Load Forecast, the Provincial Government released the BC Climate Leadership Plan that proposes several measures to increase the demand for low-carbon electricity as a strategy for reducing greenhouse gas emissions. These measures are considered in the following section.

---

⁷⁴ As seen below, 80% of the energy from Site C is expected to be surplus in F2025.

⁷⁵ The 2016 RRA does not provide a breakdown of these different factors. For the purposes of the modelling in Section 6, the entire variance between the mid-gap and the large- and small-gap scenarios has been attributed to the corresponding load forecasts.

3.4 Low-carbon electrification

Low-carbon electrification involves switching from high-carbon energy sources to low-carbon electricity, and is viewed as essential to achieving meaningful greenhouse gas emission reductions in Canada and around the world.

Fuel switching to decarbonized electricity is the single most significant pathway toward achieving deep emissions reduction globally. It allows demand sectors to reduce their end-use emissions by switching from refined petroleum products, natural gas and other fossil fuels to clean electricity.\(^{77}\)

Examples of low-carbon electrification include replacing gasoline or diesel transportation vehicles with electric vehicles, switching from natural gas space heating to electric heating (including heat pumps), and switching industrial processes away from fossil fuels to low-carbon electrical processes. The use of electricity in British Columbia to power the compression loads of liquefied natural gas (LNG) export facilities is another example of low-carbon electrification, as is the electrification of upstream natural gas facilities.

Low-carbon electrification has the potential to increase future domestic electricity requirements in British Columbia, beyond BC Hydro’s mid-load forecast. This section explores this potential in the context of several studies of low-carbon electrification conducted nationally and provincially, including by BC Hydro.

3.4.1 Low-carbon electrification in Canada

The Government of Canada’s recent climate change mitigation strategy concludes, on the basis of published, unpublished and internal analyses, that substantial quantities of large-scale hydroelectric generation, including potentially in British Columbia, are necessary for deep reductions in Canada’s greenhouse gas emissions by mid-century.\(^{78}\)

Table 4 illustrates the key findings of two of the analyses relied on by the Government of Canada in reaching its conclusions, namely the Deep Decarbonization Pathways Project (DDPP) and the Trottier Energy Futures Project (TEFP). The DDPP modeled scenarios based emission reductions on the order of 90%, while the TEFP modeled scenarios resulting in emission reductions of about 60%.\(^{79}\)

The table presents the key determinations of both of these analyses for each of the reference (business as usual) and primary low-carbon scenarios in terms of future carbon emissions, electricity requirements, and hydroelectric development in 2050.


\(^{79}\) Both studies focused on energy-related emissions, omitting land-based emissions (e.g. agriculture, forestry).
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Table 4: Analyses of low-carbon electrification in Canada

<table>
<thead>
<tr>
<th>Parameter</th>
<th>DDPP</th>
<th>TEFP</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>Reference^80</td>
<td>Low-carbon^81</td>
</tr>
<tr>
<td>Baseline CO₂e emissions^84 (MT)</td>
<td>552</td>
<td>552</td>
</tr>
<tr>
<td>2050 CO₂e emissions^85 (MT)</td>
<td>666</td>
<td>59</td>
</tr>
<tr>
<td>Δ 2050 CO₂e emissions over reference</td>
<td>-607</td>
<td>-583</td>
</tr>
<tr>
<td>CO₂e emissions change</td>
<td>+21%</td>
<td>-89%</td>
</tr>
<tr>
<td>Baseline electricity production (TWh/y)</td>
<td>600</td>
<td>600</td>
</tr>
<tr>
<td>Total electricity change (TWh/y)</td>
<td>300</td>
<td>800</td>
</tr>
<tr>
<td>Baseline hydroelectric production (TWh/y)</td>
<td>360</td>
<td>360</td>
</tr>
<tr>
<td>Total hydroelectric change (TWh/y)</td>
<td>440</td>
<td>170</td>
</tr>
<tr>
<td>Baseline electricity production (TWh/y)</td>
<td>360</td>
<td>360</td>
</tr>
<tr>
<td>Total electricity change</td>
<td>+50%</td>
<td>+133%</td>
</tr>
<tr>
<td>Total hydroelectric change</td>
<td>+122%</td>
<td>+50%</td>
</tr>
<tr>
<td>Baseline hydroelectric production (TWh/y)</td>
<td>340</td>
<td>340</td>
</tr>
<tr>
<td>Total hydroelectric change</td>
<td>+135%</td>
<td>+135%</td>
</tr>
</tbody>
</table>

As shown, the DDPP predicts an increase of 800 TWh/year in electricity generation by 2050, of which 440 TWh/year is projected to be new large-scale hydroelectric. The TEFP predicts an increase of 1550 TWh/year by 2050, of which 460 TWh/year is projected to be new large-scale hydroelectric. For context, this is equivalent to developing ninety (90) Site C Projects in Canada by 2050.

Notwithstanding their differences, both studies find that meaningful reductions in greenhouse gas emissions over the reference case are accompanied by substantial increases in electricity requirements, which would be met mainly by an unprecedented build out in large-scale hydroelectric development across Canada.

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^84 DDPP uses 2015 and TEFP uses 2013 as the baseline dates.

^85 Emissions from combustion, excludes land-use emissions.

^86 Small-scale, run-of-river hydroelectric is not considered to be competitive against other resource options.
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These studies suggest that, in a low-carbon future, the Site C Project would inevitably be needed even if BC Hydro has overestimated needs in the short- to medium-term. To explore this proposition, it is worth examining some of the key assumptions in the two studies, including in relation to projections of total electricity requirements, as well as hydroelectric requirements.

**Gross domestic product (GDP)**

Both the DDPP and the TEFP anticipate the Canadian economy will double in size by 2050, at an annualized growth rate of about 2%. The federal Department of Finance has projected long-term real economic growth to be on the order of 1.7% between 2016 and 2055. Lower economic growth would very likely result in slower growth of emissions, lower electricity requirements, and overall less investment in low-carbon electricity to 2050.

**Oil production and electricity requirements in Alberta**

The DDPP models three difference oil prices ($40, $80 and $114), while the TEFP uses a much higher range of $131.50 to $140. As summarized below in Table 5, assumptions about oil prices result in quite different long-term economic futures for the Alberta oil economy. Oil production declines modestly under mid oil prices to 3.1 Mbbl/day from 4.3 Mbbl/day in the reference case, increases considerably to 7.5 Mbbl/day under high oil prices and declines substantially to 0.85 Mbbl/day under low oil prices.

---


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Table 5: Effects of oil prices in 2050 – DDPP analysis

<table>
<thead>
<tr>
<th>Parameter</th>
<th>Reference</th>
<th>Low Oil Price</th>
<th>Mid Oil Price</th>
<th>High Oil Price</th>
</tr>
</thead>
<tbody>
<tr>
<td>Oil prices in 2050 ($/bbl)</td>
<td>80</td>
<td>40</td>
<td>80</td>
<td>114</td>
</tr>
<tr>
<td>Production in 2050 (Mbbl/day)</td>
<td>4.3</td>
<td>0.85</td>
<td>3.1</td>
<td>7.5</td>
</tr>
<tr>
<td>Alberta GDP changes in 2050 (2015=1)</td>
<td>1.71</td>
<td>1.20</td>
<td>1.34</td>
<td>1.71</td>
</tr>
<tr>
<td>British Columbia GDP changes in 2050 (2015=1)</td>
<td>2.42</td>
<td>2.17</td>
<td>2.14</td>
<td>2.10</td>
</tr>
<tr>
<td>Canadian GDP changes in 2050 (2015=1)</td>
<td>2.15</td>
<td>1.98</td>
<td>2.01</td>
<td>1.99</td>
</tr>
</tbody>
</table>

The Alberta Electricity System Operator forecasts requirements for electricity in that province to increase 11 TWh/year in its low-load forecast and 21 TWh/year in its high-load forecast by 2024 when the Site C Project would come on-line. These are substantial increases in requirements, even under the low-load scenario. Low-carbon electrification of the oilsands and growth in Alberta’s electricity requirements more generally could drive a need for imports of energy and capacity from British Columbia beyond that contemplated in BC Hydro’s recent 2016 Load Forecast.

The Canadian Energy Research Institute (CERI) recently evaluated several large-scale hydroelectric alternatives, including the Site C Project, for directly meeting the electricity needs of the oilsands through the development of addition transmission infrastructure. The CERI study also evaluated improvements to the existing transmission intertie between BC and Alberta, which could allow for additional transfers of electricity from BC to Alberta in order to meet some of the electricity needs of the oilsands.

The study found that energy from the Site C Project, including the addition of a dedicated 600-km transmission line, is the most expensive at over $140/MWh, and is therefore not considered cost effective.

This compares to the BC intertie option at about $80/MWh. The expansion of the BC-Alberta intertie could allow for increased sales of BC Hydro’s surplus energy, including surplus energy that would be created by the Site C Project. BC hydro currently forecasts an export market price at the BC-US border of $38.10/MWh in F2025 in current dollars (see Table 13, below). This is considerably higher than current market prices in Alberta, which were $18/MWh in 2016 and averaged $32/MWh over the previous three years.

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95 AESO. January 2015. Intertie Restoration Project: AESO – BCH Joint Planning Study. These improvements to the intertie would allow the rated capacity for imports into Alberta to be increased by 400 MW, from the current 800 MW import capability to 1200 MW.
96 Canadian Energy Research Institute. 2016. An Assessment of Hydroelectric Power Options to Satisfy Oil Sands Electricity Demand, p.32. (Accessed 17 April 2017 at: http://www.ceri.ca/publications-oil/) The Slave River Hydro Project was estimated at $110/MWh, with imports from new hydroelectric development in Manitoba at $125/MWh.
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while on-peak prices in 2016 were just under $20/MWh.97 While the power pool price in Alberta will continue to evolve, current prices do not suggest the development of a higher-priced market in Alberta for export of surplus energy from Site C. This would explain why BC Hydro did not analyze the future Alberta market potential in the 2013 IRP.

Alberta recently initiated its Renewable Electricity Program, which requires that all projects must be based in Alberta to be eligible for support under the program, which therefore precludes subsidies to imports from BC. In the absence of a change in the program rules, or another arrangement that would allow for surplus energy from the Site C Project to access higher prices, the Alberta market does not appear to offer higher prices than those determined by BC Hydro for markets to the south.

Finally, Alberta also recently announced the formation of a capacity market,98 beginning in 2021. BC Hydro could bid surplus capacity from the Site C Project into this market for the years when capacity is surplus following the scheduled commissioning of the Project beginning in F2024, subject to transmission capacity. Whether the Alberta capacity market will offer higher prices than the $37/kW-year for surplus capacity used by BC Hydro,99 cannot be determined at this time. In the event that further review of the Site C Project is undertaken by the BCUC, the value of future capacity should be investigated.

Electricity prices

The DDPP does not provide any information about future electricity prices or the effect of future price increases on electricity demand. In the TEFP, the marginal cost of electricity increases substantially from $0.05/kWh in the reference scenario to $0.08/kWh in the low-carbon scenario by 2025 and then stays nearly $0.03 (or 60%) higher until 2050.100 This is a substantial increase in electricity costs, yet no information is provided respecting what effect higher prices may have on future electricity demand.

Increases in electricity costs are material since the price elasticity of demand for electricity becomes more elastic over time.101,102 The result of a long-term 60% increase

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98 A “capacity market” ensures long-term grid reliability by procuring the appropriate amount of power supply resources needed to meet predicted requirements some time in the future. By matching energy supply with future energy demand, a capacity market creates long-term price signals to attract needed investments in generation infrastructure to assure adequate power supplies.
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in the real cost of electricity is that consumers are much less likely to fuel switch to electricity, more likely to adopt energy-efficient electricity alternatives, or consume less electricity. This could also include decisions by industrial customers to close production facilities or to relocate, removing substantial load from the integrated system. The lack of analytical detail respecting the effect of electricity demand elasticity in the DDPP and TEFP raises concerns that the actual electricity requirements in 2050 may be much lower than estimated.

**Demand-side management**

The DDPP and the TEFP models both apply demand-side measures across the economy. Indeed, the DDPP notes that “energy efficiency everywhere” provides 100 MT of emission reductions by 2050, a substantial reduction.\(^{103}\) In both studies, numerous graphs and pages are dedicated to explaining the specifics of the contributions from supply-side electricity resources, yet no analyses regarding the contributions of different demand-side measures are provided. There is also no discussion of the comparative cost-effectiveness of DSM. The lack of fundamental information concerning the role of DSM in either the DDPP or TEFP raises a concern about disproportionate emphasis in favour of supply-side solutions to decarbonizing the Canadian economy. As a result, actual electricity requirements in 2050 may be much lower than suggested.

**Distributed generation**

The TEFP does not include any contribution from distributed generation to 2050, based on the report’s conclusion that extensive large-scale hydroelectric generation represents the least-cost path, and would render future distributed generation uncompetitive indefinitely. The study later acknowledges that limitations in time and available funding did not allow full exploration of distributed generation.\(^{104}\) The omission of distributed generation from the analysis represents a major shortcoming in the TEFP, calling into question the findings with respect to future electricity requirements that would be met by large-scale hydroelectric development.

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\(^{103}\) SDSN and IDDRI. 2015. Pathways to deep decarbonisation in Canada ['Deep Decarbonisation Pathways Project'], Figure 9. (Accessed 17 April 2017 at [http://deepdecarbonization.org/](http://deepdecarbonization.org/)).

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**Nuclear**

The DDPP assumes that no new nuclear resources will be developed in Canada. The TEFP models the effect of no new nuclear generation and finds that in BC, in the absence of new nuclear, some new hydroelectric is developed and some pumped storage hydroelectric with additional energy resources (i.e. wind).\(^{105}\) In all other provincial jurisdictions, the TEFP determines that nuclear is replaced with pumped storage hydroelectric and additional energy resources. **This illustrates that a key trade-off in a low-carbon, low-nuclear future is between large-scale hydroelectric and a combination of energy storage with additional renewable energy resources.** Thus, the assumptions about the cost of these resources – solar PV, wind, pumped storage hydroelectric and large-scale hydroelectric – are key to forecasting which supply-side resources are likely to meet future electricity requirements.

**Solar PV**

The DDPP develops 60 TWh/year (or 4% of total requirements) of solar PV by 2050, but provides no cost information that would allow an assessment of the report’s findings. The TEFP develops essentially no solar PV in any of its scenarios, and all scenarios present less solar PV in 2050 than in 2012. **The finding in the TEFP of less generation from solar PV in Canada in 2050 than today is not credible.** As discussed in Section 5.4.1, further declines in the cost of energy from solar PV are expected to make utility-scale solar competitive with wind in many parts of Canada by 2030, increasing the role of utility-scale PV in meeting electricity requirements to 2050.

**Wind**

The DDPP develops 200 TWh/year of wind energy (or 14% of total requirements) by 2050, but provides no cost information on wind resources that would allow an assessment of wind energy’s contribution to meeting electricity requirements. The TEFP develops 550 TWh of wind energy (or 24% of total requirements) by 2050, despite the fact that the TEFP presumes no declines in the real costs of wind over the study period. **The assumption in the TEFP that real wind costs remain unchanged between 2012 and 2050 is without merit.** Section 5.4.1 below, discusses recent declines in the cost of energy from wind, which have been on the order of 20% in the past 4 years, and the extent of projected future cost declines. **Further cost declines in wind energy alter the balance of future low-carbon electricity resources towards combinations of energy storage and wind, and away from conventional large-scale hydroelectric resources.**

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**Pumped storage hydroelectric and capacity upgrades**

The DDPP contains no analysis of pumped storage hydroelectric or capacity upgrades at existing hydroelectric facilities. The omission of any electricity capacity analysis in the DDPP raises questions about the completeness, accuracy and conclusions of the study. The TEFP includes consideration of pumped storage hydroelectric, but acknowledges that the analysis entirely omitted inclusion of potential capacity upgrades at existing hydroelectric facilities. The omission in the TEFP of the potential for capacity upgrades at existing hydroelectric facilities substantially overstates the need for large-scale hydroelectric development.\(^{106}\)

**Large-scale hydroelectric**

The proposed increases in hydroelectric generation of 440 TWh/year (~72,000 MW) in the DDPP and 460 TWh/year (~75,000 MW)\(^{107}\) in the TEFP by 2050 would represent a doubling – in 30 years – of Canadian hydroelectric capacity that took over a century to develop. The total capacity of large-scale hydroelectric additions between 2000 and 2015 was on the order of 6,000 MW.\(^{108}\) The proposals in the DDPP and TEFP would represent a more than six-fold increase in the rate of large-scale hydroelectric development over the period 2020 to 2050, compared to the past 15 years.

The DDPP provides no cost information on large-scale hydroelectric development. The TEFP indicates investment costs for new large-scale hydroelectric development of $4,988/kW in lower-cost jurisdictions to $7,481/kW in higher-cost jurisdictions.\(^{109}\)

The current cost estimate of the 1100-MW Site C Project is 8.335 billion or $7,557/kW, presuming that the Project is completed on budget, which is well above the TEFP cost estimates for a lower-cost jurisdiction. As discussed further in Section 4.3.1, the actual costs of the 695-MW Keeyask Project are now estimated at $8.7 billion, or $12,518/kW, while the costs of the 824-MW Muskrat Falls Project inclusive of transmission now total $11.7 billion, or $14,200/kW. In short, the estimates of hydroelectric development costs used in the TEFP substantially understate actual large-scale hydroelectric development costs of resources currently under construction in Canada.

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\(^{108}\) Facilities larger than 100 MW in capacity.

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With respect to the location, technical feasibility and economic viability of the proposed large-scale hydroelectric facilities, the TEFP appears to rely on the summary findings of a single report that was prepared for the Canadian Hydropower Association (CHA) in 2006.\textsuperscript{110} Despite requests from the Program on Water Governance, the CHA refuses to make the full report available for public review and scrutiny. While it is unclear whether the DDPP also relies on the CHA report, other analyses,\textsuperscript{111} including the Government of Canada’s recently released climate change strategy rely on the summary findings of the same report.

The CHA is an advocate for additional hydroelectric development in Canada. The reliance by the Government of Canada, in formulating federal climate change policy, on unpublished and unreviewable research produced by the CHA concerning the feasibility of additional large-scale hydroelectric potential in Canada is concerning. The reliance on these private models and databases also greatly limits the possibility of assessing the validity of the hypotheses and conclusions.

3.4.2 Low-carbon electrification in BC

In addition to national analyses of the effects of low-carbon electrification on electricity requirements, additional estimates have been made of potential requirements in BC.

**BC Hydro’s electrification potential study**

The 2013 IRP contained a study of electrification potential (the “MKJA study”),\textsuperscript{112} the key findings of which were as follows:

- Electrification occurs across the economy in response to climate policy, particularly in the natural gas sector in the early years;
- Deep reductions in British Columbia’s GHG emissions result in substantially more electricity demand;
- Under all GHG price scenarios, the increase in electricity demand is not significant until the 2030s, due to the limitations of capital stock turnover, relatively low GHG prices, and low natural gas prices;
- Low natural gas prices constrain electrification while high natural gas prices increase electrification;

\textsuperscript{110}EEM. 2006. Study of hydropower potential in Canada. Study conducted for the Canadian Hydropower Association. Summary. (Accessed 17 April 2017 at: https://canadahydro.ca/resources/)

\textsuperscript{111}See e.g. Global Forest Watch Canada. 2012. Hydropower Developments in Canada: Number, Size and Jurisdictional and Ecological Distribution (Accessed 17 April 17 at: http://www.globalforestwatch.ca/publications/20120118AB);

Sustainable Dialogues Canada. 2015 Acting on Climate Change: Solutions from Canadian Scholars. (Accessed 17 April 17 at: http://www.sustainablecanadadialogues.ca/en/scd/endorsement)

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- Electric vehicle penetration is relatively low, even under the high GHG price scenario, due to the high capital costs of vehicle batteries.\textsuperscript{113}

The assumptions used in the MKJA study were largely matched to those used by BC Hydro in the 2013 IRP. The reference scenario used in the MKJA study is somewhat lower than BC Hydro’s 2010 Load Forecast,\textsuperscript{114} which for the years 2022 to 2030 is almost identical to BC Hydro’s 2016 Load Forecast.\textsuperscript{115} Two key inputs into the model include the following:\textsuperscript{116}

- GHG prices – low, medium and high scenarios resulting in prices (in 2005 CAD) in 2050 of $30/t, $150/t and $275/t, respectively; and
- Natural gas prices - low, medium and high scenarios resulting in prices (in 2005 CAD) in 2050 of $7/GJ, $12/GJ and $19/GJ, respectively.

Unlike the DDPP and TEF, the MKJA study does not determine specific portfolios of resources for meeting future electricity requirements. The analysis includes only technologically proven resources (primarily small hydro, wind, the Site C Project and hydroelectric pumped storage), and excludes uncertain resources (e.g. tidal and geothermal).

As shown in Table 6, and based on BC Hydro’s domestic billed sales of about 50 TWh/year in 2010, the increase in electricity requirements including electrification could range from 31\% to 69\% by 2030 and from 49\% to 120\% by 2050. Under medium GHG and medium natural gas prices, the increases are 45\% by 2030 and 86\% by 2050. The MKJA study also conducted a sensitivity analysis that concluded that lower-cost electric vehicle batteries increase electrification by an additional 15 TWh/year.\textsuperscript{117} 

\textbf{Taken together, these findings suggest that deep reductions in British Columbia’s GHG emissions result in substantially more electricity demand.\textsuperscript{118}}


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The MKJA study presents three potential scenarios for each of future GHG prices and future natural gas prices. As evident in Table 6, higher GHG prices and natural gas prices result in increased requirements for electricity:

- Under scenarios with low GHG prices and low natural gas prices, there is essentially no increase in electricity requirements over the reference scenario, even by 2050; and
- Under scenarios with high GHG prices and high natural gas prices, the projected increases in electricity requirements rise to around 100% by 2050, or double the rate of growth under the reference scenario (i.e. 56%).

Table 6: Electrification effects on energy demand, after DSM (TWh/year)

<table>
<thead>
<tr>
<th>GHG Price Scenario</th>
<th>Natural Gas Price Scenario</th>
<th>2010</th>
<th>2030</th>
<th>2050</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td></td>
<td>TWh/year</td>
<td>TWh/year</td>
<td>% change</td>
</tr>
<tr>
<td>Low</td>
<td>Low</td>
<td>51</td>
<td>67</td>
<td>31%</td>
</tr>
<tr>
<td></td>
<td>Medium</td>
<td>51</td>
<td>70</td>
<td>37%</td>
</tr>
<tr>
<td></td>
<td>High</td>
<td>51</td>
<td>77</td>
<td>51%</td>
</tr>
<tr>
<td>Medium</td>
<td>Low</td>
<td>51</td>
<td>70</td>
<td>37%</td>
</tr>
<tr>
<td></td>
<td>Medium</td>
<td>51</td>
<td>74</td>
<td>45%</td>
</tr>
<tr>
<td></td>
<td>High</td>
<td>51</td>
<td>80</td>
<td>57%</td>
</tr>
<tr>
<td>High</td>
<td>Low</td>
<td>51</td>
<td>76</td>
<td>49%</td>
</tr>
<tr>
<td></td>
<td>Medium</td>
<td>51</td>
<td>80</td>
<td>57%</td>
</tr>
<tr>
<td></td>
<td>High</td>
<td>51</td>
<td>86</td>
<td>69%</td>
</tr>
<tr>
<td>Reference (TWh/year)</td>
<td></td>
<td>50</td>
<td>67</td>
<td>34%</td>
</tr>
</tbody>
</table>

These projected increases in requirements under the “high-high” scenario (i.e. 120%) are somewhat lower than those determined in the DDPP (133%) and much lower than those in the TEFP (221%), recognizing the different geographical coverage of the studies. The overall emission reductions by 2050 with high GHG and high natural gas prices are on the order of 58 MT CO₂e/year over the reference case, or 66%, with emissions reductions much more sensitive to GHG prices than to natural gas prices.  

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Notwithstanding the potential for electrification to contribute to substantial increases in electricity requirements, several factors influencing the analysis in the MKJA study have evolved since the study was completed, including the following:

- **GHG prices** – with the recent announcement by the Government of Canada of a carbon price of $50 (nominal) by 2022,\(^{120}\) this is tracking below the medium and near to the low scenario used in the MKJA study;\(^ {121}\)
- **Natural gas prices** – natural gas prices have trended much lower than projected, and in 2016 averaged just 3.22 $/GJ,\(^ {122}\) which is substantially lower than even the low price forecast of 5.36 $/GJ for 2016 used in the MKJA study;\(^ {123}\) and
- **Information in Table 7 below, derived from BC Hydro’s 2016 RRA, suggests that electrification in the transportation sector would require less than 1,000 GWh/year by 2030, much less than anticipated in the MKJA study. This updated forecast of electricity demand from electric vehicles is already reflected in BC Hydro’s base resource plans (i.e. using the mid-load forecast) in the 2016 RRA.

Table 7: 2016 RRA electric vehicle energy requirements\(^ {124}\)

<table>
<thead>
<tr>
<th></th>
<th>F2017</th>
<th>F2019</th>
<th>F2022</th>
<th>F2027</th>
<th>F2036</th>
</tr>
</thead>
<tbody>
<tr>
<td>Energy (GWh/year)</td>
<td>&lt;50</td>
<td>&lt;50</td>
<td>70</td>
<td>430</td>
<td>1,760</td>
</tr>
<tr>
<td># Electric vehicles</td>
<td>6,000</td>
<td>11,000</td>
<td>30,000</td>
<td>164,000</td>
<td>580,000</td>
</tr>
<tr>
<td># Total vehicles</td>
<td>3,653,371</td>
<td>3,744,149</td>
<td>3,876,475</td>
<td>4,089,611</td>
<td>4,419,474</td>
</tr>
<tr>
<td>% of fleet</td>
<td>0.16</td>
<td>0.29</td>
<td>0.77</td>
<td>4.01</td>
<td>13.12</td>
</tr>
</tbody>
</table>


\(^{122}\) U.S. EIA. Henry Hub Natural Gas Spot Price. (Accessed 17 April 17 at: https://www.eia.gov/dnav/ng/hist/mgwhhdM.htm)


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The reference scenario used in the MKJA study shows an increase in energy demand of 17 TWh/year (17,000 GWh/year) between 2010 and 2030. To date, as shown above in Figure 4, there has been no growth in domestic electricity requirements since 2010. This historic pattern is not necessarily a reflection of future rates of growth, particularly if electrification is to contribute to achieving British Columbia’s climate change objectives. However, the relatively low GHG prices, much lower than anticipated natural gas prices, and low uptake of electric vehicles combine to suggest that substantial growth in electricity requirements from electrification is not on the horizon without additional significant policy intervention.

In order to capture the potential for electricity load growth to be higher than anticipated, BC Hydro’s large-gap scenario, which contemplates additional energy requirements of 7 TWh/year (before DSM) by 2030 is considered in the comparative analysis of continuing, cancelling or suspending the Site C Project presented in Section 6.3.

In summary, based on the MKJA study, deep reductions in British Columbia’s GHG emissions would result in substantially more electricity demand. However, the extent of this increase in demand and its timing remain highly uncertain. Updating the electrification analysis as part of the 2018 IRP or as part of a referral of the Site C Project to the BCUC should be considered a priority.

Electrification of LNG

BC Hydro also included in its 2016 RRA, the energy and capacity requirements of LNG export facilities for which BC Hydro has received electricity service requests. This “Expected LNG” load includes requirements from expansion of the FortisBC Tilbury Island LNG facility, Woodfibre LNG, and LNG Canada. These requirements total 2,848 GWh/year of energy and 361 MW of capacity, which is similar to the 3,000 GWh/year of energy and 360 MW of capacity included in the 2013 IRP “Expected LNG” scenario.

In the 2013 IRP, base resource plans were developed for both Expected LNG and No LNG scenarios. In the 2016 RRA, only the Expected LNG scenario is considered, despite the fact that only Woodfibre LNG has made a final investment decision. However, Woodfibre LNG has not yet executed an electricity supply agreement nor...

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secured binding LNG supply contracts.  

BC Hydro’s approach therefore overlooks the possibility that not all of the LNG projects will be developed.

Since the release of the 2016 RRA, Pacific Northwest LNG (which was not included in the Expected LNG scenario) received conditional environmental assessment approval from the federal government. That conditional approval included a hard cap on annual greenhouse gas emissions from the project. In addition, the Canadian Environmental Assessment Agency concluded that using electricity from the BC Hydro grid to meet the 215 MW (~1,800 GWh/year) of non-compression loads at the project site would be technically feasible. No public indication has been given as to whether Pacific Northwest LNG intends to make a service request to BC Hydro for meeting its non-compression loads.

The potential energy and capacity requirements of these four LNG facilities are summarized in Table 8 below.

Table 8: Potential LNG energy and capacity requirements

<table>
<thead>
<tr>
<th></th>
<th>Woodfibre LNG</th>
<th>LNG Canada</th>
<th>Tilbury Island LNG</th>
<th>Pacific Northwest LNG</th>
</tr>
</thead>
<tbody>
<tr>
<td>Non-compression load</td>
<td>Grid</td>
<td>Grid</td>
<td>Grid</td>
<td>TBD&lt;sup&gt;135&lt;/sup&gt;</td>
</tr>
<tr>
<td>Compression load</td>
<td>Grid</td>
<td>Self</td>
<td>Grid</td>
<td>Self</td>
</tr>
<tr>
<td>Electricity service request</td>
<td>Yes</td>
<td>Yes</td>
<td>Yes</td>
<td>No</td>
</tr>
<tr>
<td>Capacity (MW)</td>
<td>185</td>
<td>157</td>
<td>19</td>
<td>215</td>
</tr>
<tr>
<td>Energy (GWh/year) (est.)</td>
<td>1,300</td>
<td>1,400</td>
<td>148</td>
<td>1,800</td>
</tr>
<tr>
<td>Final investment decision</td>
<td>Yes</td>
<td>No</td>
<td>No</td>
<td>No</td>
</tr>
</tbody>
</table>

Currently, the Domestic Long-Term Sales Contracts Regulation<sup>136</sup> stipulates the LNG electricity rate for each year from 2015 to 2023. The LNG rate energy charge will be the greater of the energy charges set out in Table 9 below and the energy charges set out in Rate Schedule 1823, as amended from time to time.

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<sup>135</sup> Energy and capacity requirements presume grid supply for non-compression loads.

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As part of the Climate Leadership Plan, Government and BC Hydro announced a new eDrive rate to encourage LNG proponents to use electricity for their natural gas compression (i.e. liquefaction) needs. The rate applies to the total load of the facility and is only available to proponents that use electricity for both their ancillary and compression power needs and connect at transmission voltage.

Table 9 compares the two rates (not including the demand charge), with the eDrive rate increasing at the rates stipulated in the 10 Year Rates Plan until F2019, and at a rate of 2.6% for each of the years 2020 to 2023, consistent with the rates proposed in BC Hydro’s 2016 RRA. The eDrive rate will have the same energy charges as Rate Schedule 1823, the existing transmission service rate. The LNG and eDrive rates also have the same demand charge as Rate Schedule 1823.

Table 9: Comparison of LNG, eDrive and industrial rates

<table>
<thead>
<tr>
<th>Calendar Year</th>
<th>LNG rate energy charge</th>
<th>eDrive energy charge (equivalent to Rate Schedule 1823B)</th>
<th>Rate Schedule 1823A</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>($/MWh)</td>
<td>Tier 1 ($/MWh)</td>
<td>Tier 2 ($/MWh)</td>
</tr>
<tr>
<td>2017</td>
<td>76.85</td>
<td>39.81</td>
<td>89.2</td>
</tr>
<tr>
<td>2018</td>
<td>78.39</td>
<td>41.21</td>
<td>92.32</td>
</tr>
<tr>
<td>2019</td>
<td>79.96</td>
<td>42.44</td>
<td>95.09</td>
</tr>
<tr>
<td>2020</td>
<td>81.56</td>
<td>43.54</td>
<td>97.56</td>
</tr>
<tr>
<td>2021</td>
<td>83.19</td>
<td>44.68</td>
<td>100.1</td>
</tr>
<tr>
<td>2022</td>
<td>84.85</td>
<td>47.03</td>
<td>105.37</td>
</tr>
<tr>
<td>2023</td>
<td>86.55</td>
<td>48.25</td>
<td>108.11</td>
</tr>
</tbody>
</table>

Woodfibre LNG and Tilbury Island LNG already plan to use electricity for their compression loads, and this is included in the requirements in Table 8. As for Pacific Northwest LNG and LNG Canada, BC Hydro notes that a fully electric two-train LNG facility producing 12 million tonnes per year of LNG would require 500-600MW, or 4,000-5,000 GWh/year of electricity. With respect to Pacific Northwest LNG, BC Hydro.

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138 The LNG rate is specified to 2023 and remains constant after this date.
139 See: BC Hydro Transmission Service Rates. Available at: https://www.bchydro.com/accounts-billing/rates-energy-use/electricity-rates/transmission_rate.html. 1823A is a flat rate rate, and 1823B is a tiered rate with Tier 2 designed to encourage conservation.
140 The LNG energy charge rates are based on a calendar year and are effective January 1 of each year.
141 Rate Schedule 1823A rates are set on a fiscal year basis and are effective April 1 each year.
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Hydro has indicated that the available transfer capacity on the transmission line servicing the Prince Rupert Port lands is limited to not more than 250 MW.\(^{143}\) LNG customers on the eDrive Rate are required to contribute the full cost of transmission system connection as well as any upgrades required to serve their facilities, as set out in electricity supply and load interconnection agreements with BC Hydro.\(^{144}\) As such, electrification of compression loads at the Pacific Northwest LNG facility is not currently feasible, and cannot become feasible unless Pacific Northwest LNG were to pay the full cost of necessary transmission system upgrades. To date, neither LNG Canada nor Pacific Northwest LNG has indicated an intention to use electricity for their compression loads.

**BC Climate Leadership Plan**

The Climate Leadership Plan sets out a number of actions, designed to support BC’s climate change policy objectives:

- supply 100% of electricity for the integrated grid from clean or renewable sources, except where concerns regarding reliability or costs must be addressed;
- electrification of natural gas production, processing and transmission, all currently fuelled by natural gas and diesel fuel, to reduce greenhouse gas emissions;
- expanding the mandate of BC Hydro’s DSM programs to include investments that increase efficiency and reduce GHG emissions;
- expanding the Clean Energy Vehicle Program; and
- amending the energy efficiency standards regulation.

In response to the Climate Leadership Plan, BC Hydro prepared a preliminary briefing note exploring the potential implications of low-carbon electrification for electricity requirements. The briefing note contains the following key messages:

- The full impact of these policy developments on the extent and timing of electrification is highly uncertain, and will be evaluated in detail in preparation for the 2018 Integrated Resource Plan (IRP). This will include a new load forecast.

- Although the extent of electrification is uncertain, the directional impact is clear, and a number of studies and analyses provide an indication of the potential for increased low-carbon electrification in BC.


- Some of the most significant near-term (pre-2030) potential for electrification is in the natural gas sector, and BC Hydro is working with government and stakeholders to explore program initiatives in this area.

- BC Hydro is also exploring electrification opportunities in other sectors, including residential, commercial, other industrial (mining) and transportation (vehicles, ports and airports).

- If low-carbon electrification programs proceed, BC Hydro anticipates that electrification loads could exceed what is currently estimated in the load forecast and will be able to reflect that in future load forecasts.\textsuperscript{145}

BC Hydro also noted that the potential combined effect of the transportation, efficiency and electrification measures contained in the Climate Leadership Plan could increase electricity requirements by up to 6,500 to 7,000 GWh/year by 2030. This remains consistent with the analysis in the 2013 IRP, which envisioned an increase of up to 7,000 GWh/year over baseline in the medium scenario, as shown in Table 6.

The briefing note also emphasizes that BC Hydro’s 2016 Load Forecast already includes a significant amount of electrification, particularly related to LNG (2,848 GWh/year by F2024), natural gas production, processing and transmission (3,507 GWh/year by F2030),\textsuperscript{146} and the requirements related to electric vehicles summarized in Table 7. The Climate Leadership Plan is considered in greater detail below in Section 5.4.2 dealing with capacity resources, particularly simple cycle gas turbines and pumped storage hydroelectric.

\textbf{Vancouver Renewable City Strategy}

In its briefing note, BC Hydro also explored the potential implications of the Vancouver Renewable City Strategy. The primary objectives of this Strategy are to derive 100% of the energy used in Vancouver from renewable sources, and to reduce greenhouse gas emissions by at least 80% below 2007 levels, both by 2050. The Strategy does not include specific policies designed to achieve these ambitious goals, which are yet to be developed.

The main contributor to emissions reduction in the Strategy is energy conservation, which contrasts with BC Hydro’s current approach to developing the Site C Project while moderating spending on DSM into the foreseeable future. The Strategy targets reducing total energy use by 35%, even with an allowance for economic and demographic


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growth. This amounts to an increase in electricity requirements of only 1,111 GWh/year by 2050, or about 20% above current levels.\footnote{City of Vancouver. 2015. Renewable City Strategy 2015-2050, p.36. (Accessed 17 April 17 at: http://vancouver.ca/files/cov/renewable-city-strategy-booklet-2015.pdf)}

Considering the lack of specific policy in relation to the targets in the Strategy, there are significant uncertainties that may increase the City’s future requirements for electricity. These include the extent of development of neighbourhood renewable energy systems, and the contributions of biofuels and biomethane. In the Strategy, these resources collectively provide about 15 million GJ/year of energy or about 40% of total energy requirements in 2050. If these resources were unavailable or not cost-effective, then reliance on electricity from BC Hydro would be higher.


- the current policy scenario;
- a Strategy scenario, including policies adopted to date in relation to the Strategy; and
- a 100% renewable energy scenario consisting of policies in the Strategy scenario with additional policies designed to get closer to the two primary objectives of the Strategy.

The review is limited to the residential, commercial, light industrial and transportation sectors, and does not address the heavy industrial sector.

One of the additional assumptions in the review is that large supplies of renewable natural gas (RNG) will not be available to the Vancouver region at a cost that is competitive with renewable electricity for building end uses, or for district heating. This is a key assumption that limits the use of renewable natural gas to a few niche applications, and perhaps a few high-density locations suitable for district heating. The review also reaches the conclusion, assessed further in Section 5.4.3 below, that solar PV will not become cost-effective in Vancouver by 2050 compared to electricity generated by BC Hydro.

The findings of the review with respect to electricity use under the three scenarios are summarized in Table 10.
**Table 10: Vancouver potential future electricity requirements (GWh/year)**

<table>
<thead>
<tr>
<th></th>
<th>Residential Buildings</th>
<th>Commercial Buildings</th>
<th>Transport</th>
<th>Total</th>
<th>Growth</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>2015</td>
<td>2050</td>
<td>2015</td>
<td>2050</td>
<td>2015</td>
</tr>
<tr>
<td>Current Policies</td>
<td>1,667</td>
<td>2,857</td>
<td>3,056</td>
<td>3,667</td>
<td>0</td>
</tr>
<tr>
<td>Strategy Policies</td>
<td>1,667</td>
<td>3,095</td>
<td>3,056</td>
<td>3,544</td>
<td>0</td>
</tr>
<tr>
<td>100% Renewables</td>
<td>1,667</td>
<td>4,286</td>
<td>3,056</td>
<td>4,156</td>
<td>0</td>
</tr>
</tbody>
</table>

Under current policies, electricity growth over the 35-year period from 2015 to 2050 across the residential, commercial and transportation sectors was projected to be on the order of 38%. Under the Strategy scenario, the review finds that electricity growth is 40% over the 35-year period or double the 20% increase determined in the Strategy. The 40% growth rate is more consistent with the rate of increase in BC Hydro’s 2016 Load Forecast, which projects 20% load growth (net of DSM) system-wide by 2030.150 Under the policies designed to achieve 100% renewables, the review predicts that electricity consumption will nearly double, growing by 90%.

In summary, similar to the province-wide analyses conducted by BC Hydro in the 2013 IRP, projections of electricity load growth for the City of Vancouver vary widely in a low-carbon future. These estimates range from 20% to 90% between 2015 and 2050 depending on a myriad of factors, including:

- the extent and success of DSM;
- the relative costs of DSM, distributed generation, renewable natural gas, and electricity from BC Hydro; and
- the force and effect of regional, provincial and national policies.

As the review of the Vancouver Renewable City Strategy notes, the additional policies designed to meet the objectives of the Strategy largely involve fuel switching from fossils fuels to electricity, and depend on assumptions about the future cost and availability of RNG for which the research acknowledges there are “substantial uncertainties”.151

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3.4.3 Implications of low-carbon electrification

In summary, the direction of electricity requirements resulting from electrification is clear — they will increase.

The increases in electricity requirements in the DDPP and TEFP, which are on the order of 130% and 220% above current requirements by 2050, are not defensible based on the information provided in these analyses.

In its 2013 IRP electrification analysis, BC Hydro projected that requirements for additional electricity inclusive of low-carbon electrification could increase between 49% and 120% by 2050, depending on future natural gas and GHG prices. Since that time, however, there have been no increases in electricity requirements.

The Vancouver Renewable City Strategy predicts that its total electricity requirements, inclusive of low-carbon electrification, will grow only 20% by 2050. However, a critical review of the Strategy, making different policy assumptions found that electricity requirements would need to increase on the order of 90% to achieve the objectives of the Strategy.

Though available information indicates that the effects of electrification on BC Hydro’s load forecast are likely to be significant, the timing and extent of those increases remains highly uncertain.

The preponderance of information points to a significant effect from electrification beginning not sooner than the 2030s. The possible exception concerns the electrification of natural gas production, processing, transmission and liquefaction, which is currently underway and already included in BC Hydro’s 2016 Load Forecast.

The 2018 IRP or a referral of the Site C Project for review by the BCUC would provide the opportunity for BC Hydro to review the full impact of policy developments on the extent and timing of electrification, and to prepare a new load forecast.

3.5 Summary

The justification for proceeding with the Site C Project at this time hinges on BC Hydro’s forecast that the province’s electricity needs will grow by 40% over the next 20 years. Importantly, this is before accounting for energy savings from conservation and efficiency (i.e. DSM). After accounting for DSM, BC Hydro’s most recent forecast projects that electricity needs will grow by 30%, meaning that BC Hydro is projecting that DSM will play only a modest role in reducing future electricity requirements.

Since Site C was initially proposed in the early 1980s, BC Hydro’s load forecasts have consistently overstated future growth in electricity requirements. As demonstrated in

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Section 3.2.5, BC Hydro’s forecasters have overestimated 10-year, 15-year and 20-year future requirements consistently for the past several decades. The risk is the development of additional higher-cost supply-side resources producing large amounts of surplus energy that must be sold into export markets at a considerable loss.

With the collapse of BC Hydro’s 2012 Load Forecast, energy from the Site C Project will be surplus when the Project comes on-line – even with the inclusion of “Expected LNG” load, a large portion of which remains uncertain. While additional load from electrification may help to mitigate the losses associated with this energy surplus, these additional requirements remain highly uncertain and may not be material until well into the 2030s.

As a result of these ongoing and future energy surpluses, the question facing BC Hydro is no longer whether to proceed as soon as possible with a resource portfolio containing the Site C Project or an alternative portfolio containing other supply-side resources, as analyzed in the 2013 IRP.

The decision now facing BC Hydro is whether to:

a) continue with construction of the Site C Project to completion as scheduled;

b) cancel the Site C Project in order to develop alternative resources; or

c) suspend the Site C Project and develop alternative resources as needed, but leave open the possibility of continuing the Site C Project if circumstances warrant.

These alternatives are discussed further below in Sections 4 and 5, respectively.
4. Option: Continue development of the Site C Project

4.1 Introduction

As indicated in Section 3.5, the decision now facing BC Hydro is whether to:

a) continue with construction of the Site C Project to completion as scheduled;

b) cancel the Site C Project in order to develop alternative resources;

or

c) suspend the Site C Project and develop alternative resources as needed, but leave open the possibility of continuing the Site C Project if circumstances warrant.

This section explores the costs and risks of continuing with the Site C Project to completion as scheduled. Section 4.2 discusses the costs of the Site C Project, including costs incurred to date. Section 4.2.4 explores the costs related to the GHG emissions from the Site C Project. The potential for and implications of cost overruns in the development of the Site C Project is discussed in Section 4.3. This is followed by a discussion in Section 4.4 of the losses due to the energy surplus that would be created by the Site C Project. Section 4.5 summarizes the findings associated with the option of continuing the Site C Project to completion as scheduled.

4.2 Site C Project costs

4.2.1 Initial project cost estimates

In terms of project costs, the Site C Project budget summary is provided in Table 11.

Table 11: Site C Project budget summary¹⁵³

<table>
<thead>
<tr>
<th>Description</th>
<th>Capital Amount (Nominal $ million)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Dam, Power Facilities and Associated Structures</td>
<td>4,120</td>
</tr>
<tr>
<td>Offsite Works, Management and Services</td>
<td>1,575</td>
</tr>
<tr>
<td><strong>Total Direct Construction Cost</strong></td>
<td><strong>5,695</strong></td>
</tr>
<tr>
<td>Indirect Costs</td>
<td>1,235</td>
</tr>
<tr>
<td><strong>Total Construction and Development Cost</strong></td>
<td><strong>6,930</strong></td>
</tr>
<tr>
<td>Interest During Construction</td>
<td>1,405</td>
</tr>
<tr>
<td><strong>Project Cost, before Treasury Board Reserve</strong></td>
<td><strong>8,335</strong></td>
</tr>
<tr>
<td>Treasury Board Reserve</td>
<td>440</td>
</tr>
<tr>
<td><strong>Total Project Cost</strong></td>
<td><strong>8,775</strong></td>
</tr>
</tbody>
</table>

The total capital cost of the Site C Project, including interest during construction is estimated at $8.335 billion (nominal\textsuperscript{154}), excluding the $440 million Treasury Board reserve. This represents about a 5% increase to the capital cost estimate of $7.9 billion used to evaluate the Site C Project against the alternatives in the 2013 IRP and in the environmental assessment.\textsuperscript{155}

These capital costs would translate into a series of annual costs to be paid by ratepayers following commissioning of the Project. BC Hydro reported this annual cost to be about $510 million (nominal) over a 70-year period following commissioning.\textsuperscript{156} Though the BC Utilities Commission would ultimately determine the annual amounts to be paid by ratepayers and the term for those payments, this annual cost allows for annual and net present value comparisons of costs between the Site C Project and alternative demand-side and supply-side resources that could be used to meet BC Hydro’s electricity requirements. Any costs of the Site C Project that are not transferred to ratepayers would be covered by taxpayers (as shareholders of BC Hydro), whether as direct costs or as foregone dividends.

\textbf{4.2.2 Cost to ratepayers: 10 Year Rates Plan}

In December 2014, at the time of the decision to proceed with the Site C Project, the Provincial Government explained the cost to ratepayers of energy from Site C as a result of the Government’s 10 Year Rates Plan for BC Hydro.\textsuperscript{157} Under the Plan, the amount of net income that BC Hydro is required to earn each year will be tied to inflation from F2018 until F2024 and, during that period, will no longer increase when new assets are added to the system. Under the Plan, new assets will be financed at a cost approximating the cost of debt, as opposed to being financed based on a weighted average cost of debt and equity, which reflects the higher risk associated with an equity investment.

In a backgrounder entitled “Comparing the Options”,\textsuperscript{158} the Province and BC Hydro indicate that the unit energy cost for Site C would decline by $26/MWh as a result of these changes, and by an additional $1/MWh due to a reduction in water rental charges. The result is an updated unit energy cost of $58-$61/MWh, as opposed to $85-

\textsuperscript{154} As of the commissioning date.
\textsuperscript{156} Government of British Columbia and BC Hydro. “Site C to provide more than 100 years of affordable, reliable clean power.” Backgrounder: Comparing the Options. (Accessed 17 April 2017 at https://news.gov.bc.ca/stories/site-c-to-provide-more-than-100-years-of-affordable-reliable-clean-power)
\textsuperscript{158} Government of British Columbia and BC Hydro. “Site C to provide more than 100 years of affordable, reliable clean power”. Backgrounder: Comparing the Options. (Accessed 17 April 2017 at https://news.gov.bc.ca/stories/site-c-to-provide-more-than-100-years-of-affordable-reliable-clean-power)
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$88/MWh. (The $2.50/MWh range reflects the $440 million Treasury Board reserve, which may not be fully required.)

However, there is no reason to believe that the 10 Year Rates Plan, which expires in March 2024, would affect the regulatory treatment of the Site C Project, which enters the rate base only after commissioning. BC Hydro makes clear in its 2016 RRA that “the 10 Year Rates Plan did not include the Site C Clean Energy Project” and that it “has not yet determined how it will have the impact of the Site C Clean Energy Project come into rates.”

The current government has not committed to continue the Plan after it expires and, even if it did make such a commitment, it cannot bind future governments. Moreover, there is no guarantee that future governments will maintain the 10 Year Plan to its scheduled conclusion.

There is thus no reason to assume that the 10 Year Rates Plan will affect the financing of the Site C Project. Furthermore, even if the Plan were extended to include the Site C Project, the difference in cost would consist of monies that would otherwise be paid as dividends to the Provincial Government as the sole owner of BC Hydro. This would not affect the actual costs of the Project, but only the allocation of those costs between ratepayer and taxpayer.

4.2.3 Costs incurred to date

From F2007 until the third quarter of F2015, BC Hydro incurred costs in relation to planning and development of the Site C Project and deferred these costs into a regulatory account. In its responses to information requests filed during the 2016 RRA, BC Hydro confirmed that the deferral account for the Site C Project stands at $453 million at the end of F2017 (March 31, 2017). In its most recent 2017/18 to 2019/20 Service Plan, BC Hydro reported total capital expenditures of $1,268 million to the end of F2017.

By the end of F2018, BC Hydro budgets total capital expenditures of $1,844 million and total deferred costs of $472 million, for a total of $2,316 million. Prorating these amounts, anticipated capital expenditures would total $1,412 million and deferred costs $458 million, for a total of $1.87 billion by June 30, 2017. Looked at another way,

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disregarding sunk costs, as of June 30, 2017 the cost of completing the Site C Project will be $6.465 billion (~80% of the original budget).

These costs are used in the scenarios developed in Section 6.3 assessing the conditions under which it is preferable to continue, cancel or suspend the Site C Project.

4.2.4 Greenhouse gas emissions from the Site C Project

In a previous study, one of this report’s authors explored in detail the expected GHG emissions of the Site C Project. Figure 13 presents BC Hydro’s “likely” and “conservative” estimates of annual greenhouse gas emissions that the Site C Project would produce, where emissions prior to F2024 reflect construction-related emissions and emissions following F2024 indicate operating emissions. Figure 14 presents the cumulative GHG emissions of the Site C Project over the first forty years of operations.

Figure 13: Annual GHG emissions of the Site C Project

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The cost of construction phase GHG emissions are implicitly included in the construction costs of the Site C Project to the extent that the existing carbon tax of $30/tonne of GHG emissions applies to fuel, materials and equipment. However, GHG emissions from the operations phase were not included in the cost estimate. Using the price of $50/tonne in 2022 announced by the Government of Canada, and assuming that this price will increase with inflation, we estimate the cost associated with GHG emissions from the Site C reservoir to be as indicated in Figure 15. These costs are included in the scenarios developed in Section 6.3 assessing the conditions under which it is preferable to continue, cancel or suspend the Site C Project.


4.3 Site C Project cost uncertainties

4.3.1 Potential for cost overruns

BC Hydro’s recent annual and quarterly progress reports also provide updates on the progress of construction of the Site C Project. As noted in the F2017 first quarter progress report, several key milestones were delayed by several months, including in relation to the main civil works. BC Hydro notes that the overall progression of work remains on track to achieve the scheduled in-service dates, but that the success of re-sequencing of work to address delays over the fall and winter “is not yet determined”\(^\text{167}\). BC Hydro also notes that: “Any cost impacts to BC Hydro associated with rescheduling activities can be managed from existing contingency budgets.”\(^\text{168}\)

Several other factors outlined in the Annual Progress Report could potentially contribute to cost overruns in relation to the Site C Project, including the following:

- First Nations opposition;
- Ongoing litigation;
- Permitting delays;


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- Labour costs or instability;
- Material and equipment costs;
- Construction execution;
- Exchange rates;
- Interest rates; and
- Tax rates.

In addition to the above are geotechnical risks, which BC Hydro notes include unexpected shears encountered during construction, deeper than expected relaxation joints, bedding planes worse than expected, larger than expected deterioration of shale bedrock once exposed during construction, and rock rebound/swell. The tension crack that formed recently along the north bank is an example of a geotechnical risk faced by the Project.\(^\text{169}\) These geotechnical risks represent one of the more significant threats to the schedule and costs of the Project at this stage, since they will only be more fully understood as major excavation and tunnelling continues in 2017.\(^\text{170}\)

To the extent that the Site C Project is delayed or incurs unanticipated costs that exceed contingencies, construction costs and debt servicing costs will increase. As of December 31, 2016, $285 million of a total available contingency of $1.04 billion had been expended.\(^\text{171}\)

Internationally, large hydro projects tend to exceed initial project budgets by an average of 27%.\(^\text{172}\) Outside of Quebec, where large-scale hydro development is more frequent, costs of large-scale, greenfield hydroelectric and transmission developments in Canada follow a similar pattern, as illustrated in Table 12.


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## Table 12: Recent large-scale hydroelectric and transmission project costs

<table>
<thead>
<tr>
<th>Hydro Projects</th>
<th>Proponent</th>
<th>Capacity</th>
<th>Total Cost</th>
<th>Overrun</th>
<th>Status</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td></td>
<td></td>
<td>Initial</td>
<td>Actual</td>
<td>$</td>
</tr>
<tr>
<td></td>
<td></td>
<td></td>
<td>$2.9B</td>
<td>$5.1B</td>
<td>$2.2B</td>
</tr>
<tr>
<td>Muskrat Falls(^\text{173,174})</td>
<td>Nalcor Energy</td>
<td>824 MW</td>
<td>$0.9B</td>
<td>$1.6B</td>
<td>$0.7B</td>
</tr>
<tr>
<td>Wuskwatim(^\text{175,176})</td>
<td>Manitoba Hydro</td>
<td>200 MW</td>
<td>$6.2B</td>
<td>$8.7B</td>
<td>$2.5B</td>
</tr>
<tr>
<td>Keeyask(^\text{177,178,179})</td>
<td>Manitoba Hydro</td>
<td>695 MW</td>
<td>$222M</td>
<td>$296M</td>
<td>$74M</td>
</tr>
</tbody>
</table>

**Transmission Projects**

| Labrador-Island Transmission Link\(^\text{180}\) | Nalcor Energy | +/-350kV | $2.6B | $3.4B | $1.2B | +31% | ~50% constructed |
|Bipole III\(^\text{181,182}\) | Manitoba Hydro | 500 kV | $3.3B | $5.4B | $2.1B | +64% | ~50% constructed |

---


176 Wuskwatim Power Limited Partnership. About the Wuskwatim Generating Station. (Accessed 17 April 17 at [http://www.wuskwatim.ca/project.html](http://www.wuskwatim.ca/project.html))


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<table>
<thead>
<tr>
<th>Transmission Project(^{183,184})</th>
<th>Developer</th>
<th>Voltage</th>
<th>Cost Yr 1</th>
<th>Cost Yr 2</th>
<th>Cost Yr 3</th>
<th>Cost Yr 4</th>
<th>Cost Overrun</th>
<th>Status</th>
</tr>
</thead>
<tbody>
<tr>
<td>Interior to Lower Mainland Transmission Line(^{185,186})</td>
<td>BC Hydro</td>
<td>500kV</td>
<td>$602M</td>
<td>$743M</td>
<td>$141M</td>
<td>$141M</td>
<td>+23%</td>
<td>Operating</td>
</tr>
<tr>
<td>Northwest Transmission Line(^{187,188})</td>
<td>BC Hydro</td>
<td>287kV</td>
<td>$404M</td>
<td>$716M</td>
<td>$312M</td>
<td>$312M</td>
<td>+77%</td>
<td>Operating</td>
</tr>
</tbody>
</table>

BC Hydro has not developed a large-scale greenfield hydroelectric project since the Revelstoke Generating Station commissioned in 1984, but it has developed large-scale greenfield transmission projects. The weighted cost overrun for BC Hydro’s three most recent large-scale greenfield transmission projects was on the order of 43%.

Overall, BC Hydro reports that from F2012 to F2016, it completed 563 capital projects at an overall cost of $6.49 billion, or 0.18% under budget.\(^{189}\) Considering that this value includes the projects in the above table, it would appear that BC Hydro’s performance on smaller-scale and brownfield projects has been far superior to its performance on larger-scale, greenfield projects.


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4.3.2 Quantifying potential cost overruns

The potential for Site C Project cost overruns is relevant to the decision to continue, cancel or suspend the Project. Considering that the Project remains in the early stages of construction, with about 80% of project costs yet to be incurred, the extent of eventual cost overruns, if any, cannot be fully determined at this point.

For every 10% that the Site C Project is over budget, total costs increase on the order of $800 million (nominal). For example, a cost overrun of 23% (on par with that for the Interior to Lower Mainland Transmission Line) would amount to $1.9 billion, or more than what has been expended on the project to date. A cost overrun of 43%, consistent with BC Hydro’s performance on its most recent three large-scale transmission lines, would see a cost overrun of $3.6 billion for a total cost on the order of $11.9 billion.

A cost overrun of 43% or $3.6 billion on the Site C Project may appear excessive or unreasonable, but not when viewed in the context of similar projects:

- the Muskrat Falls Project (76% cost overrun) and the Keeyask Hydroelectric Project (40% cost overrun) make a 43% cost overrun at Site C appear not exceptional;
- the Muskrat Falls + Labrador Island Transmission (combined cost overrun $3.4 billion or 62%) and the Keeyask + Bipole III (combined cost overrun $4.6 billion or 48%) also make a $3.6 billion cost overrun at Site C appear not unreasonable.

This does not mean that the Site C Project will necessarily incur a cost overrun. Rather, it is reasonable to expect that there may be cost overruns for the Site C Project, based on recent experience with greenfield hydroelectric and transmission projects across Canada, including BC Hydro projects. However, the full extent of any cost overruns will not be known until the Project is further advanced. The potential for cost overruns adds an additional element of risk to the development of the Site C Project that is addressed further in the scenarios developed in Section 6.3 assessing the conditions under which it is preferable to continue, cancel or suspend the Site C Project.

4.4 Losses due to the Site C Project energy surplus

Based on the load resource balances presented by BC Hydro in the 2016 RRA,\textsuperscript{190} the Site C Project is now forecast to create an energy surplus that would last for a period of about 8 years following commissioning in F2024. This energy surplus creates additional costs that may not be immediately obvious.

A capital-intensive project like Site C is financed much like a mortgage -- there is a fixed amount to be paid each year to cover the debt and the return on BC Hydro’s equity investment. The annual amount of these combined costs is divided by the number of

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kWh produced each year to give the unit cost that must be recovered through electricity sales.

When the energy is sold to regulated consumers, their rates are set high enough to cover this cost. However, when the energy is exported, it is the export market that sets the sales price. When the sales price is not sufficient to cover the unit costs, then the shortfall must be made up either by regulated ratepayers through increased rates, or by taxpayers through reduced dividends (or cash injections to BC Hydro).

Because current and foreseeable market prices are far below the unit cost of Site C energy, any energy surplus will inevitably create losses of this type. The ultimate size and duration of the surplus cannot be known with certainty until years following the commissioning of the Site C Project, but can be estimated based on BC Hydro’s 2016 Load Forecast.

4.4.1 Projected surplus under the mid-load forecast scenario

BC Hydro’s 2016 RRA mid-load forecast indicates that the Site C Project will be entirely surplus to domestic requirements when it comes on-line in F2024. Concerns about the implications of this energy surplus were raised by the JRP, which wrote in its final report:

BC Hydro’s outlook is that the market prices it would achieve through the forecast period would average only $35/MWh, radically less than the marginal cost of production and delivery (about $94/MWh\(^{191}\))[at that time; now $85 to $88/MWh\(^{192}\)]. Site C would be a large, sudden addition to supply. BC Hydro projects losing $800 million [nominal] in the first 4 years of operation. These losses would come home to B.C. ratepayers in one way or another.\(^{193}\)

BC Hydro now anticipates that when the Project comes on line, an energy surplus would persist for 7 years under its mid-load scenario.\(^{194}\) Though surplus energy would need to be sold on export markets, in the 2013 IRP BC Hydro made clear its perspective on the prospects for export sales of clean energy:

Since the enactment of the CEA, the prospects of export sales of clean or renewable energy in excess of that required to meet B.C. self-sufficiency

\(^{191}\) The current estimate is about $85 to $88/MWh.

\(^{192}\) Government of British Columbia and BC Hydro. “Site C to provide more than 100 years of affordable, reliable clean power”. Backgrounder: Comparing the Options. See also, Section 4.2.2, above. (Accessed 17 April 2017 at https://news.gov.bc.ca/stories/site-c-to-provide-more-than-100-years-of-affordable-reliable-clean-power)


requirements have diminished considerably. Further, the prospects of such sales are not expected to materially improve over the short to medium term. 195

More recently, in its 2016 Revenue Requirements Application (RRA), BC Hydro reiterated this perspective: prospects are poor for potential export markets for renewable electricity generated in British Columbia. 196

In its 2013 IRP, BC Hydro presented forecasts for future export market prices for sales of electricity into the U.S. market at the international border. Additional price forecasts were also considered by varying the expected price of electricity in the export markets, GHG prices and natural gas prices (the price-setting fuel in the US Northwest). BC Hydro updated these price forecasts in its 2016 RRA, as illustrated in Table 13.

The prices in this table reflect a single price forecast. In reality, there is considerable uncertainty respecting the potential value of surplus energy sales from the Site C Project. Specifically, these forecasts are very sensitive to the future evolution of the USD/CAD exchange rate, to electricity prices, to natural gas prices, and to carbon prices, among other factors. The 2013 IRP used an exchange rate of 0.9693 USD/CAD, which is much higher than today’s rates, or the average long-term exchange rate of 0.82 USD/CAD used in Table 13. Failing to capture the uncertainty associated with future exchange rate variations, natural gas prices and other variables understates the financial risks associated with the Project.

These price forecasts make possible the development of an initial estimate of the potential losses from the Site C Project that would result from having to sell surplus energy on export markets. As shown in Table 14, in this price scenario and based on BC Hydro’s mid-load forecast, the resulting losses rise to $235 million in F2026 before eventually receding to $0 by F2032.

---


Table 13: B.C. electricity export sales market prices\(^{197,198}\)

<table>
<thead>
<tr>
<th>Year</th>
<th>Mid-C Market Prices(^{199})</th>
<th>Exchange rate</th>
<th>Mid-C Market Prices</th>
<th>Wheeling/loss Adjuster</th>
<th>B.C. Border Sell Price - Calendar Year</th>
<th>B.C. Border Sell Price - Fiscal Year</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>$2016 USD/MWh</td>
<td>USD/CAD</td>
<td>$2016 CAD/MWh</td>
<td>$2016 CAD/MWh</td>
<td>$2016 CAD/MWh</td>
<td>$2016 CAD/MWh</td>
</tr>
<tr>
<td>2017</td>
<td>23.2</td>
<td>0.78</td>
<td>29.74</td>
<td>6.3</td>
<td>23.44</td>
<td></td>
</tr>
<tr>
<td>2018</td>
<td>24.1</td>
<td>0.8</td>
<td>30.13</td>
<td>6.3</td>
<td>23.83</td>
<td>23.54</td>
</tr>
<tr>
<td>2019</td>
<td>27.2</td>
<td>0.82</td>
<td>33.17</td>
<td>6.3</td>
<td>26.87</td>
<td>24.59</td>
</tr>
<tr>
<td>2020</td>
<td>30.2</td>
<td>0.82</td>
<td>36.83</td>
<td>6.3</td>
<td>30.53</td>
<td>27.79</td>
</tr>
<tr>
<td>2021</td>
<td>32.5</td>
<td>0.82</td>
<td>39.63</td>
<td>6.3</td>
<td>33.33</td>
<td>31.23</td>
</tr>
<tr>
<td>2022</td>
<td>33.7</td>
<td>0.82</td>
<td>41.10</td>
<td>6.3</td>
<td>34.80</td>
<td>33.70</td>
</tr>
<tr>
<td>2023</td>
<td>35.0</td>
<td>0.82</td>
<td>42.68</td>
<td>6.3</td>
<td>36.38</td>
<td>35.19</td>
</tr>
<tr>
<td>2024</td>
<td>35.4</td>
<td>0.82</td>
<td>43.17</td>
<td>6.3</td>
<td>36.87</td>
<td>36.50</td>
</tr>
<tr>
<td>2025</td>
<td>36.2</td>
<td>0.82</td>
<td>44.15</td>
<td>6.3</td>
<td>37.85</td>
<td>37.11</td>
</tr>
<tr>
<td>2026</td>
<td>37.2</td>
<td>0.82</td>
<td>45.37</td>
<td>6.3</td>
<td>39.07</td>
<td>38.15</td>
</tr>
<tr>
<td>2027</td>
<td>38.1</td>
<td>0.82</td>
<td>46.46</td>
<td>6.3</td>
<td>40.16</td>
<td>39.34</td>
</tr>
<tr>
<td>2028</td>
<td>38.6</td>
<td>0.82</td>
<td>47.07</td>
<td>6.3</td>
<td>40.77</td>
<td>40.32</td>
</tr>
<tr>
<td>2029</td>
<td>39.9</td>
<td>0.82</td>
<td>48.66</td>
<td>6.3</td>
<td>42.36</td>
<td>41.17</td>
</tr>
<tr>
<td>2030</td>
<td>41.4</td>
<td>0.82</td>
<td>50.49</td>
<td>6.3</td>
<td>44.19</td>
<td>42.82</td>
</tr>
<tr>
<td>2031</td>
<td>43.0</td>
<td>0.82</td>
<td>52.44</td>
<td>6.3</td>
<td>46.14</td>
<td>44.68</td>
</tr>
<tr>
<td>2032</td>
<td>43.8</td>
<td>0.82</td>
<td>53.41</td>
<td>6.3</td>
<td>47.11</td>
<td>46.38</td>
</tr>
<tr>
<td>2033</td>
<td>44.7</td>
<td>0.82</td>
<td>54.51</td>
<td>6.3</td>
<td>48.21</td>
<td>47.39</td>
</tr>
<tr>
<td>2034</td>
<td>45.6</td>
<td>0.82</td>
<td>55.63</td>
<td>6.3</td>
<td>49.33</td>
<td>48.49</td>
</tr>
<tr>
<td>2035</td>
<td>46.6</td>
<td>0.82</td>
<td>56.78</td>
<td>6.3</td>
<td>50.48</td>
<td>49.62</td>
</tr>
<tr>
<td>2036</td>
<td>47.5</td>
<td>0.82</td>
<td>57.94</td>
<td>6.3</td>
<td>51.64</td>
<td>50.77</td>
</tr>
<tr>
<td>2037</td>
<td>48.5</td>
<td>0.82</td>
<td>59.13</td>
<td>6.3</td>
<td>52.83</td>
<td>51.94</td>
</tr>
</tbody>
</table>


\(^{198}\) The export market prices are determined from Mid Columbia (Mid-C) market prices, converted to Canadian dollars, adjusted for transmission wheeling costs and line losses, and converted to BC Hydro’s fiscal years.

\(^{199}\) Mid-C” refers to the Mid-Columbia electricity hub, a reference location for electricity prices in the United States Northwest, the market region into which electricity from the Site C Project would be exported.
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Table 14: Implications of the Site C energy surplus

<table>
<thead>
<tr>
<th>Year</th>
<th>Site C Energy Surplus (GWh)</th>
<th>B.C. Energy (GWh)</th>
<th>Site C Energy used in BC (GWh)</th>
<th>Site C Energy sold as surplus (GWh)</th>
<th>% of Site C Energy that is Surplus</th>
<th>B.C. Border Sell Price (CA$2016/MWh)</th>
</tr>
</thead>
<tbody>
<tr>
<td>2024</td>
<td>388</td>
<td>720</td>
<td>0</td>
<td>388</td>
<td>100%</td>
<td>36.5</td>
</tr>
<tr>
<td>2025</td>
<td>4,435</td>
<td>3,459</td>
<td>976</td>
<td>3,459</td>
<td>78%</td>
<td>37.1</td>
</tr>
<tr>
<td>2026</td>
<td>5,100</td>
<td>3,976</td>
<td>1,124</td>
<td>3,976</td>
<td>78%</td>
<td>38.2</td>
</tr>
<tr>
<td>2027</td>
<td>5,100</td>
<td>3,395</td>
<td>1,705</td>
<td>3,395</td>
<td>67%</td>
<td>39.3</td>
</tr>
<tr>
<td>2028</td>
<td>5,100</td>
<td>2,621</td>
<td>2,479</td>
<td>2,621</td>
<td>51%</td>
<td>40.3</td>
</tr>
<tr>
<td>2029</td>
<td>5,100</td>
<td>1,845</td>
<td>3,255</td>
<td>1,845</td>
<td>36%</td>
<td>41.2</td>
</tr>
<tr>
<td>2030</td>
<td>5,100</td>
<td>1,014</td>
<td>4,086</td>
<td>1,014</td>
<td>20%</td>
<td>42.8</td>
</tr>
<tr>
<td>2031</td>
<td>5,100</td>
<td>187</td>
<td>4,913</td>
<td>187</td>
<td>4%</td>
<td>44.7</td>
</tr>
<tr>
<td>2032</td>
<td>5,100</td>
<td>-</td>
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<td>46.4</td>
</tr>
<tr>
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<td>5,100</td>
<td>-</td>
<td>5,100</td>
<td>-</td>
<td>0%</td>
<td>47.4</td>
</tr>
<tr>
<td>2034</td>
<td>5,100</td>
<td>-</td>
<td>5,100</td>
<td>-</td>
<td>0%</td>
<td>48.5</td>
</tr>
<tr>
<td>2035</td>
<td>5,100</td>
<td>-</td>
<td>5,100</td>
<td>-</td>
<td>0%</td>
<td>49.6</td>
</tr>
<tr>
<td>2036</td>
<td>5,100</td>
<td>-</td>
<td>5,100</td>
<td>-</td>
<td>0%</td>
<td>50.8</td>
</tr>
</tbody>
</table>

<table>
<thead>
<tr>
<th>Year</th>
<th>Site C Energy Surplus Revenues ($M) (CA$2016 M)</th>
<th>Site C Annual Cost ($M)(^{200}) (CA$2016 M)</th>
<th>Site C Costs Net of Sales Revenues (CA$2016 M)</th>
<th>Costs attributable to surplus (CA$2016 M)</th>
<th>Annual loss attributable to surplus (CA$2016 M)</th>
<th>Cumulative loss attributable to surplus (CA$2016 M)</th>
</tr>
</thead>
<tbody>
<tr>
<td>2024</td>
<td>14.16</td>
<td>0</td>
<td>0</td>
<td>0</td>
<td>0</td>
<td>0</td>
</tr>
<tr>
<td>2025</td>
<td>128</td>
<td>440</td>
<td>311</td>
<td>343</td>
<td>214</td>
<td>214</td>
</tr>
<tr>
<td>2026</td>
<td>152</td>
<td>496</td>
<td>344</td>
<td>386</td>
<td>235</td>
<td>449</td>
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<td>2027</td>
<td>134</td>
<td>486</td>
<td>352</td>
<td>323</td>
<td>190</td>
<td>639</td>
</tr>
<tr>
<td>2028</td>
<td>106</td>
<td>476</td>
<td>371</td>
<td>245</td>
<td>139</td>
<td>778</td>
</tr>
<tr>
<td>2029</td>
<td>76</td>
<td>467</td>
<td>391</td>
<td>169</td>
<td>93</td>
<td>871</td>
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<td>2030</td>
<td>43</td>
<td>458</td>
<td>414</td>
<td>91</td>
<td>48</td>
<td>919</td>
</tr>
<tr>
<td>2031</td>
<td>8</td>
<td>449</td>
<td>441</td>
<td>16</td>
<td>8</td>
<td>927</td>
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<td>440</td>
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<td>0</td>
<td>927</td>
</tr>
<tr>
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<td>431</td>
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<td>927</td>
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<td>2034</td>
<td>0</td>
<td>423</td>
<td>423</td>
<td>0</td>
<td>0</td>
<td>927</td>
</tr>
<tr>
<td>2035</td>
<td>0</td>
<td>415</td>
<td>415</td>
<td>0</td>
<td>0</td>
<td>927</td>
</tr>
<tr>
<td>2036</td>
<td>0</td>
<td>407</td>
<td>407</td>
<td>0</td>
<td>0</td>
<td>927</td>
</tr>
</tbody>
</table>

\(^{200}\) These values represent the fixed nominal-dollar cost of the Site C Project, expressed in constant 2016$. 

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The findings in Table 14 are presented graphically in Figure 16 below. The solid green line illustrates the cumulative cost of the energy surplus. The dashed blue line shows the percent of Site C energy that is surplus each year.\textsuperscript{201} As the percentage of Site C that is surplus declines to zero, the cumulative losses due to the surplus level off at the value of $927 million shown in 2036 in Table 14.

**Figure 16: Losses due to the Site C Project energy surplus (mid-load forecast)**

In summary, the losses due to the energy surplus created when the Site C Project is commissioned are an important consideration in evaluating the relative risks and costs of the Project. These losses do not appear in BC Hydro’s determination of project costs summarized in Section 4.2.1, yet they are material to comparing the Project against the available alternatives, which can be developed modularly so as not to create a similar energy surplus. The extent of these losses depends not only on market prices, exchange rates and natural gas prices but also on the accuracy of BC Hydro’s load forecasts.

\textsuperscript{201} Table 14 and Figure 16 omit the small amount of energy to be produced by Site C in F2024, which is expected to be 100% surplus to BC requirements.
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forecasts. Additional scenarios are developed in Section 6.3 assessing the conditions under which it is preferable to continue, cancel or suspend the Site C Project.

4.4.2 Potential surplus under the high-load and low-load forecast scenarios

In the event that the need for energy grows faster than anticipated, the losses resulting from the Site C Project surplus will be less than the $927 million illustrated above. For example, under BC Hydro’s high-load scenario, the rapid growth in energy requirements would reduce the surplus to three years, and the resulting losses to just $279 million.

Considering that BC Hydro’s mid-load forecasts have consistently overstated actual future demand, there remains a very real possibility that the surplus created by the Site C Project will persist longer than anticipated. Under the low-load scenario contained in the 2016 RRA, Site C is 100% surplus until F2036, and the costs to ratepayers by that time are on the order of $2.7 billion, with additional costs thereafter (Figure 17).

Figure 17: Losses due to the Site C Project energy surplus (low-load forecast)

As long as the energy from Site C is entirely surplus, the losses borne by ratepayers will be on average $225 million per year, declining from $300 million in F2026 to $150 million in F2036 as the annual cost of Site C in real dollars declines and market prices increase.
4.5 Summary

The key observations respecting the costs of continuing with development of the Site C Project are as follows:

- The current projected capital cost of the Site C Project, excluding the $440 million Treasury Board reserve, is $8.335 billion, which is about 5% higher than the $7.9 billion used to evaluate the Site C Project against the alternatives in the 2013 IRP;

- BC Hydro has expended $458 million in deferred costs and $1,412 million in capital costs for a total of $1,870 million by June 30, 2017;

- Following the first year of construction, the Site C Project has experienced some delays, but BC Hydro anticipates that any cost impacts associated with rescheduling activities can be managed from existing contingency budgets;

- In the event that the Site C Project has a cost overrun of 43% comparable to BC Hydro’s most recent three greenfield transmission projects, the cost of the Site C Project would rise by $3.6 billion to a total of $11.9 billion;

- The cumulative losses resulting from the surplus created by the Site C Project under BC Hydro’s mid-load forecast and the market price forecast in the 2016 RRA are on the order of $950 million; and

- Under BC Hydro’s low-load forecast, the cumulative losses resulting from the Site C energy surplus would be on the order of $2.7 billion by F2036 and would continue to increase thereafter.
5. Options: cancel the Site C Project, or suspend the Site C Project

5.1 Introduction

Pursuant to Section 3.5, BC Hydro now has the following three options:

- a) continue with construction of the Site C Project to completion as scheduled;
- b) cancel the Site C Project in order to develop alternative resources; or
- c) suspend the Site C Project and develop alternative resources as needed, but leave open the possibility of continuing the Site C Project if circumstances warrant.

This Section 5 begins with an analysis in Section 5.2 of costs associated with cancelling or suspending the Site C Project. The costs to cancel include addressing sunk costs to date and costs related to contract cancellation and demobilization. The costs to suspend also include addressing sunk costs to date, contract cancellation and demobilization. Suspension also includes costs to maintain the site in suspension, and to remobilize to the site in the event that Site C becomes cost effective at a future date.

Section 5.3 evaluates the demand-side resources (i.e. DSM) that would need to be developed in the event that Site C is cancelled or suspended. Similarly, Section 5.4 evaluates the supply-side resource (i.e. wind, natural gas, etc.) that would need to be developed in the event that Site C is cancelled or suspended. Section 5.5 summarizes the findings.

5.2 Site C Project cancellation and suspension costs

5.2.1 Sunk costs

Any potential decision to cancel or suspend the Site C Project must take into consideration costs already spent in developing the Project. As these sunk costs increase, the opportunity to pursue an alternative path fades. As indicated in Section 4.2.3, total expenditures to the end of June 30, 2017 were projected to be $1.87 billion, leaving $6.465 billion to be spent. Therefore, development of an alternative portfolio of resources must be evaluated against a suspended Site C Project that can be realized at an additional cost of just $6.465 billion, plus remobilization costs, and not the full project cost of $8.335 billion.

In the event that the Site C Project is cancelled, these sunk costs will need to be repaid. It is presumed that these costs are repaid over a 70-year period, similar to the repayment of the Site C Project if it were developed to completion. Suspension of the Site C Project must consider the cost to carry these sunk costs until a decision is made to either continue or cancel the Project.

5.2.2 Cancellation costs

The cancellation of the Site C Project would entail contractual costs (e.g. contract breakage, remediation), including demobilization costs, which must also be considered. The magnitude of these costs would depend on the terms of any contracts signed to
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date, information that has not been publicly divulged. However, the value of the major contracts executed to date is provided in BC Hydro’s most recent project progress update, and shown in Table 15. The total value of minor contracts (valued at less than $10 million) was not provided by BC Hydro.

Table 15: Major Site C Project contracts awarded (to December 2016)\textsuperscript{202}

<table>
<thead>
<tr>
<th>Work Package</th>
<th>Contract Value ($M)</th>
<th>Current Status</th>
</tr>
</thead>
<tbody>
<tr>
<td>Site Preparation: North Bank</td>
<td>60</td>
<td>Executed July 2015, and includes amendments to December 2016</td>
</tr>
<tr>
<td>Worker Accommodation</td>
<td>465</td>
<td>Executed September 2015</td>
</tr>
<tr>
<td>Main Civil Works</td>
<td>1,750</td>
<td>Executed December 2015</td>
</tr>
<tr>
<td>Turbine-Generator</td>
<td>464</td>
<td>Executed March 2016</td>
</tr>
<tr>
<td><strong>TOTAL</strong></td>
<td><strong>2,739</strong></td>
<td></td>
</tr>
</tbody>
</table>

Cancellation of the Site C Project would entail costs for demobilization. These costs would include:

- Removing equipment, personnel and materials from the site;
- Securing quarries and borrow areas and allowing them to flood in accordance with permit conditions;
- Stabilizing any rock or overburden stockpiles in accordance with permit conditions;
- Removing any fuels, chemicals and explosives from the site; and
- Securing mechanical, hydraulic and electrical systems.

A recent review of Manitoba Hydro’s 695 MW Keeyask Project on the Nelson River in northern Manitoba indicated that $2.5 billion, or 39% of project development costs of $6.5 billion, had been spent as of September 2016.\textsuperscript{203} Cancelling that project at that stage would have triggered on the order of $1.3 billion in contract cancellation costs.\textsuperscript{204} The Site C Project will have expended approximately $1.412 billion in capital costs (excluding deferred costs) by June 30, 2017, with more than $2.730 billion contracted.


Based on the proportions in the Keeyask Project review, cancellation costs for the Site C Project as of June 30, 2017 are estimated to be on the order of $600 million to $900 million, including demobilization costs. For the purposes of the analysis in Section 6.3, an amount of $750 million for contractual and demobilization costs is estimated.

The Site C Project has faced considerable First Nation and public opposition, as well as ongoing litigation. The potential for disruption of construction or revocation of permits issued to allow the Project to proceed suggests that BC Hydro would have exercised caution before entering into construction contracts to ensure that the interests of ratepayers were protected in the event of disruption or cancellation.

However, the extent to which BC Hydro was successful in negotiating cancellation or suspension clauses into these contracts cannot be determined, since contractual arrangements with the many contractors working on the Site C Project are confidential. Without access to the Site C construction contracts, the contract cancellation costs represent a significant unknown cost in evaluating the options to continue, cancel or suspend the Site C Project.

Typically, the BCUC would have access to these contracts were the Commission to review the Site C Project. In the event that the Site C Project is referred to the BCUC for further review, these cancellation costs should be further evaluated.

5.2.3 Suspension costs

Contract cancellation and demobilization costs are presumed for the purposes of the analysis in this report not to apply to a suspended Site C Project. To the extent that the Project is suspended for an extended period of time, it is quite likely that contract cancellation costs will be triggered. Considering the significant uncertainty respecting the magnitude of these costs, the details of any payments to contractors in a suspension period are for further consideration in the event that the Site C Project is referred for further review to the BC Utilities Commission.

Following demobilization of non-essential equipment and materials, additional ongoing costs would be incurred for maintenance and monitoring if the Site C Project is suspended but not cancelled. These costs could include the following:

- Securing the site from visitors for protection of the public through the provision of fencing or other measures;
- Maintaining the site in a secure condition through provision of continuous security;
- Periodically inspecting any rock or overburden stockpiles;
- Securing and maintaining all facilities to remain on-site during suspension; and

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- Continuing with environmental monitoring programs in accordance with permit conditions.

No large-scale hydroelectric projects are currently in a state of suspended construction in Canada. The costs to suspend the Site C Project are therefore estimated to be on the order of $15 million per year based on the annual site maintenance costs at a large and currently suspended mine site. In the event that the Site C Project is referred to the BCUC for further review, these suspension costs should be further evaluated.

5.2.4 Remobilization and continuation costs

Costs to remobilize the construction site following a suspension of the Site C Project would likely be similar to costs to initially mobilize to the site in the summer and fall of 2015 (i.e. Q2 and Q3 of F2016). However, these costs were not specifically reported by BC Hydro. In its quarterly progress report for the third quarter of F2016 ending December 31, 2015, BC Hydro reported actual project costs to that date of $694 million. These costs would include deferred costs incurred prior to mobilization, which were $432 million as of that date. This suggests that about $270 million was expended during the first five months on-site, which provides an initial order of magnitude estimate of site mobilization costs. Not all of these costs would have been related to mobilization, and remobilization is likely to be somewhat less costly than mobilization. An estimated amount of $200 million (or about 3% of initial construction costs) is added to the remaining cost of $6.465 billion following suspension, for a total of $6.665 billion to restart the development of the Site C Project should it become cost effective at some future date.

5.2.5 Summary of costs related to cancellation or suspension

The following table summarizes the costs related to cancellation and suspension, respectively. These costs are integrated into the analysis in Section 6.3 assessing the conditions under which it is preferable to continue, cancel or suspend the Site C Project.

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Table 16: Summary of cost to cancel or suspend the Site C Project

<table>
<thead>
<tr>
<th>Cost Item</th>
<th>Cancel the Site C Project</th>
<th>Suspend the Site C Project</th>
</tr>
</thead>
<tbody>
<tr>
<td>Sunk costs</td>
<td>$1.87 billion</td>
<td>$1.87 billion</td>
</tr>
<tr>
<td>Contractual and demobilization costs</td>
<td>$750 million</td>
<td>n/a</td>
</tr>
<tr>
<td>Suspension costs</td>
<td>n/a</td>
<td>$15 million/year</td>
</tr>
<tr>
<td>Remobilization costs</td>
<td>n/a</td>
<td>$200 million</td>
</tr>
</tbody>
</table>

5.3 Evaluating demand-side resources

Following cancellation or suspension of the Site C Project, it would be necessary for BC Hydro to advance other resources in order to meet future requirements for energy or capacity. Any future scenarios involving a cancelled or suspended Site C Project would require additional investment in demand-side measures beyond that currently contemplated by BC Hydro, and in advance of higher-cost supply-side resources.

The *Clean Energy Act* defines ‘demand-side measure’ (DSM) to mean:

“a rate, measure, action or program undertaken (a) to conserve energy or promote energy efficiency; (b) to reduce the energy demand a public utility must serve; or (c) to shift the use of energy to periods of lower demand … but does not include (d) a rate, measure, action or program the main purpose of which is to encourage a switch from the use of one kind of energy to another such that the switch would increase greenhouse gas emissions in British Columbia, or (e) any rate, measure, action or program prescribed.”

BC Hydro develops and implements two forms of DSM: energy-focused DSM and capacity-focused DSM. The former involves measures designed to conserve energy, promote energy efficiency and reduce customer energy demand. Capacity-focused measures target additional capacity savings during BC Hydro’s peak load periods. These two forms of DSM are discussed below.

5.3.1 Energy-focused demand-side management

Since the 2013 IRP, BC Hydro has made a number of decisions that have resulted in a considerable reduction in the role that DSM plays in meeting requirements for energy and capacity. These decisions have had implications for the need to advance higher-cost supply-side resources, including the Site C Project.

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209 *Clean Energy Act*, SBC 2010, c 22
BC Hydro relies on three general approaches to energy-focused DSM:

- **Codes and standards**: public policy instruments enacted by governments to influence energy efficiency (e.g. building codes, appliance standards, local government zoning);
- **Conservation rate structures**: inclining block (stepped) rate structures (for residential, commercial and industrial customers) designed to reduce electricity consumption; and
- **Programs**: designed to support codes and standards and rate structures, as well as to address the remaining barriers to energy efficiency and conservation after codes and standards and rate structures, thereby capturing additional conservation potential.\(^{210}\)

Historically, these demand-side resources have focused on reducing energy needs, though they also provide capacity savings. BC Hydro’s 2013 IRP identified DSM options that targeted increasing energy and associated capacity savings by F2021. Each of these options is described briefly below.

**Table 17: Energy-focused DSM Options\(^{211}\)**

<table>
<thead>
<tr>
<th>DSM Option</th>
<th>Energy Savings by F2021 (GWh/year)</th>
<th>Capacity Savings by F2021 (MW)</th>
<th>Description</th>
</tr>
</thead>
<tbody>
<tr>
<td>Option 1</td>
<td>6,100</td>
<td>1,200</td>
<td>Minimum required to meet the <em>Clean Energy Act</em> objective of reducing BC Hydro’s “expected increase in demand for electricity by the year 2020 by at least 66%”</td>
</tr>
<tr>
<td>Option 2</td>
<td>7,800</td>
<td>1,400</td>
<td>The DSM Target used in the 2013 IRP</td>
</tr>
<tr>
<td>Option 3</td>
<td>8,300</td>
<td>1,500</td>
<td>Targets additional electricity savings beyond Option 2 by expanding program efforts, while keeping codes and standards and conservation rate structures unchanged</td>
</tr>
<tr>
<td>Option 4</td>
<td>9,500</td>
<td>1,500</td>
<td>Based on new or more aggressive conservation rate structures, and significant government regulation in the form of codes and standards</td>
</tr>
<tr>
<td>Option 5</td>
<td>9,600</td>
<td>1,600</td>
<td>Creates a future where most buildings are net-zero consumers of electricity with some buildings being net contributors of electricity back to the grid</td>
</tr>
</tbody>
</table>

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BC Hydro selected Option 2 as its DSM Target for use in the 2013 IRP, despite the fact that Option 3 represented (in 2013) the “greatest level of DSM program savings currently considered deliverable.”\(^{212}\) BC Hydro determined that the additional cost to the utility to implement DSM Option 3 as opposed to DSM Option 2 was on the order of $50 million per year.\(^{213}\)

The decision not to proceed with DSM Option 3 was the result of BC Hydro’s ongoing energy surplus, which the utility believed at that time would be short-lived, and the utility’s desire to reduce near-term costs. Indeed, BC Hydro recommended in the 2013 IRP to moderate (i.e. reduce) program spending for DSM Option 2 in the near term (F2014 through F2016), in order to reduce costs further without compromising the ability to ramp up to the DSM Target seven years later, in F2021.\(^{214}\)

Since the approval of the 2013 IRP, it is now clear that the energy surplus will continue well into the future, meaning that a return to DSM Option 2 would exacerbate the surplus. In the 2016 RRA, BC Hydro confirmed that it is proposing to further extend the “moderation” of DSM program spending through F2017 – F2019.\(^{215}\) Moreover, this moderation strategy is being extended as an assumption for F2020 and beyond, pending further review as part of the 2018 IRP.\(^{216}\)

The consequences of these successive moderations to DSM spending are not immaterial for the need to develop new, and costlier, supply-side resources, including the Site C Project. During the proceedings for its 2016 RRA, and in response to an information request seeking to understand the implications of further moderation of DSM, BC Hydro filed information updating DSM Option 2. This information reflected a similar level of activity as the DSM plan included in the 2013 IRP, but incorporated changes from new market information, including “lower than planned savings from conservation rates, increased savings from codes and standards, and changes to


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programs based on more up to date market information.\textsuperscript{217} This information makes it possible to assess the energy and capacity savings of DSM Option 2 if it were not moderated beyond F2016 as currently proposed by BC Hydro.

As Figure 18 illustrates, initially selecting DSM Option 3 would have provided more than 10,000 GWh/year of energy and more than 1800 MW of capacity savings by F2024.\textsuperscript{218} The decision in the 2013 IRP to proceed with DSM Option 2 reduced those savings to under 9000 GWh/year and 1600 MW.\textsuperscript{219} The further decision to moderate DSM Option 2 during the F2014 to F2016 period reduced those savings further to 8400 GWh/year and less than 1500 MW,\textsuperscript{220} and now the proposal in the 2016 RRA to further moderate DSM would reduce those savings to about 6700 GWh/year and 1200 MW.\textsuperscript{221}

The cumulative effect of BC Hydro’s decisions to moderate DSM during and following the 2013 IRP is more than 3,000 GWh/year and 600 MW by F2024. This is more than 50% of the Site C Project at 5,100 GWh/year of energy and 1100 MW of capacity.

In short, BC Hydro is abandoning Recommended Action #1 of the 2013 IRP consisting of a DSM Target of 7,800 GWh/year by F2021 with associated capacity savings of 1400 MW. The utility’s most recent proposal would have DSM reduce its expected increase in demand by 76% between F2008 and F2021,\textsuperscript{222} which still exceeds the minimum of at least 66%, as required by the \textit{Clean Energy Act}.\textsuperscript{223} However, the recent plan significantly reduces the contribution under DSM Option 2, which in the mid-load


\textsuperscript{218} BC Hydro. November 2013. Integrated Resource Plan, Figure 3-1 and Figure 3-2.


\textsuperscript{223} Subsection 2(b) of the Clean Energy Act “to take demand-side measures and to conserve energy, including the objective of [BC Hydro] reducing its expected increase in demand for electricity by year 2020 [by year fiscal 2021 from fiscal 2008] by at least 66 per cent”.
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forecast would see DSM meeting 85% of new requirements (with LNG)\textsuperscript{224}, or 116% of new requirements (without LNG)\textsuperscript{225}.

Figure 18: DSM options available to BC Hydro since the 2013 IRP

a) Energy-focused DSM energy savings

\begin{figure}[h]
\centering
\includegraphics[width=\textwidth]{figure18.png}
\caption{DSM options available to BC Hydro since the 2013 IRP}
\end{figure}


b) Energy-focused DSM capacity savings

Based on the 2016 Load Forecast, had DSM Option 3 been pursued from F2014 to F2024, this would have had the effect of delaying the need for new energy resources by five years, from F2025 to F2030. Additional savings from DSM Option 3 after F2024 would only further delay the need for new resources beyond F2030.

**The costs of DSM**

As noted above, BC Hydro reduces its near-term costs by reducing its commitment to DSM program spending, with the cost savings between DSM Option 3 and DSM Option 2 on the order of $50 million/year. BC Hydro reported further expected cost savings of about $100 million per year to continue the moderation of DSM Option 2 as contemplated in the 2016 RRA. Overall, the cost difference between DSM Option 3 and the DSM Plan contemplated in the 2016 RRA appears to be on the order of $150 million/year.

Relative to all of BC Hydro’s supply-side resources, including the Site C Project, BC Hydro’s DSM programs are very cost-effective. This cost-effectiveness is determined in accordance with the Utility Cost (UC) and the Total Resource Cost

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227 The UC measures the costs of the DSM initiative from the utility’s perspective, excluding any costs of the participant, and indicate the change in total utility bills (revenue requirements) due to DSM.
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(TRC)\textsuperscript{228} tests, and evaluated by the BC Utilities Commission in accordance with the Demand-side Measures Regulation.\textsuperscript{229}

The 2013 IRP reported that the unit energy cost for DSM Option 2 from the TRC perspective was $32/MWh while that from for the UC perspective was $18/MWh.\textsuperscript{230} In the 2016 RRA, BC Hydro reported DSM Option 2 total resource cost of $46/MWh and utility cost of $29/MWh, respectively.\textsuperscript{231} The utility cost of DSM programs under BC Hydro’s proposed revised DSM Plan is $22/MWh.\textsuperscript{232} These costs reflect the weighted average of many demand-side measures. They compare to the levelized cost of energy from the Site C Project of $85 to $88/MWh, as discussed further in Section 4.2.2,\textsuperscript{233} and the current long-run marginal cost of energy from clean resources (i.e. wind) of $100/MWh.\textsuperscript{234}

**BC Hydro is continuing to cancel or scale back many DSM programs that have utility costs well below the unit energy costs of the Site C Project, at $85 to $88/MWh.**\textsuperscript{235}

As it did in the 2013 IRP, BC Hydro provides a rationale for extending the moderation of DSM beyond F2016 based on a desire to lower near-term costs:

\begin{quote}
BC Hydro notes that it did not select an alternative with higher expenditure levels because, in part, it would increase rates relative to the proposed Demand-Side
\end{quote}

\textsuperscript{228} The TRC measures the overall economic efficiency of a DSM initiative from a resources options perspective, including both participant and utility costs. The BCUC has determined that individual DSM programs should be assessed to determine if they pass a TRC cost/benefit ratio of 1.0, and any programs not exceeding this ratio must be justified.

\textsuperscript{229} B.C. Reg 326/2008. The Demand-Side Measures Regulation also guides the BCUC’s determination of cost effectiveness by providing modifications to the TRC test that the Commission must follow when assessing DSM expenditures.


\textsuperscript{233} See Section 4.2.2, above.


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Management Plan. This upward pressure on rates would challenge BC Hydro’s ability to meet the targets under the 2013 10 Year Rates Plan.\(^{236}\)

It is important to provide some context respecting the confluence of events that have lead BC Hydro to conclude that it is necessary to continue to moderate spending on lower cost DSM, while at the same time advancing the much higher-cost Site C Project.

First, the Provincial Government approved the Site C Project in the context of the 2012 and 2013 Load Forecasts. As illustrated in Figure 6, these forecasts predicted energy requirements in F2024 that exceed those now predicted in the 2016 Load Forecast by 6,290 GWh/year and 14,244 GWh/year, respectively. For context, the Site C Project would produce 5,100 GWh/year.

Secondly, with this collapse in BC Hydro’s load forecast, the utility is now forecasting $3.5 billion less revenue than when the 10-Year Rates Plan was announced. The only way to recoup those lost revenues is to increase rates.\(^{237}\) However, the 10-Year Rates Plan imposes a freeze on rate increases until F2019, at levels much lower than BC Hydro’s actual revenue requirements in the period F2017 to F2019 with the shortfalls to be deferred to future rate increases in the period F2020 to F2024.\(^{238}\)

Moreover, the updated load resource balance contained in the 2016 RRA now predicts that the energy surplus will extend to F2025, beyond the scheduled in-service date for the Site C Project. As such, additional savings from DSM would only exacerbate the costly Site C energy surplus. Thus, in order to prevent even higher future increases in rates and to mitigate the losses due to the Site C Project energy surplus, BC Hydro must moderate spending on lower cost DSM in hopes that consumers will consume more.

In summary, BC Hydro finds it preferable to curtail DSM. The utility is taking this action in order to reduce near-term losses from its ongoing energy surplus and future losses from surpluses that the Site C Project would create if commissioned as planned in F2024. This action is being taken despite the fact that DSM delivers electricity at a fraction of the cost of electricity from the Site C Project.


BC Hydro’s long-term DSM plan

In evaluating the long-term utility of its DSM programs, BC Hydro assumes that average DSM persistence is about 19 years,\(^{239}\) depending on the program and the technology employed. At the end of this period, since the savings are no longer incremental to what would have otherwise occurred, they are removed from the DSM plan. However, following F2021, no new additional demand-side measures are contemplated to replace and improve upon existing measures. This situation is illustrated in Figure 19 derived from BC Hydro’s 2016 RRA, where new DSM measures cease after F2021 and the additional energy savings from DSM decline by more than 40% by F2024 and to zero by F2036.

Figure 19: 2016 RRA DSM Plan – annual incremental energy\(^{240}\)

The approach taken by BC Hydro can be contrasted with that taken by the Ontario IESO. Figure 20 illustrates the anticipated savings from DSM programs, codes and standards in Ontario over the same 20-year planning period as BC Hydro’s 2016 RRA.


BC Hydro includes only what the IESO refers to as “historic program persistence” (yellow bars) and “forecast savings from planned programs” (blue bars). BC Hydro presumes that the additional savings from “codes and standards implemented by 2015” (turquoise bars) will decay to zero over the 20-year period, while the IESO sees these savings persisting to the end of the period. Most importantly, BC Hydro includes no savings from future programs, codes and standards (the green and red bars) that the Ontario IESO notes form the vast majority of DSM savings by the end of the planning period.

Figure 20: Ontario IESO conservation achievement and outlook

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BC Hydro’s position that no new additional demand-side measures will be developed following F2021 to replace and improve upon existing measures is not credible. LED lights, time-of-use prices, load curtailment, programmable thermostats, community energy planning, micro-grids, real-time data analytics, smart meters, and direct load control are just a few of the many electricity management innovations of recent years. There is no reason to believe that human inventiveness will suddenly come to an end in 2020. The following expert testimony before the Manitoba Public Utilities Board speaks to this issue:

The challenge of DSM for planning purposes, then, becomes the challenge of predicting innovations: we know they will happen, but we don’t know exactly how or how much. Yet the reverse is true too: we know that a static view – one in which future DSM savings are limited to the savings opportunities available today – is wholly inappropriate for a long-term planning horizon, much less one covering the coming 20 years. 242

The conclusion in the 2016 RRA that DSM will cease to make any new contributions to meeting BC Hydro’s needs beyond F2021, and any contributions at all beyond F2036, implies abandoning the Clean Energy Act Objective 2(b) without any public policy acknowledgement or debate.

The Clean Energy Act, in section 2(b), sets what appeared at the time to be an ambitious objective of meeting 66% of BC Hydro’s demand growth with DSM, until the year 2020 – but was silent about the longer-term future.

While, strictly speaking, there is no requirement for BC Hydro to develop new DSM measures beyond 2020 (F2021), there is also no reason to believe that the intent of the Clean Energy Act was to aggressively ramp down DSM after that date. Moreover, in the current context of low load growth, there is potential for cost-effective DSM to meet much more than 66% of new demand going forward, as it has for the past decade. When a decision has been taken in the face of stagnant load growth to advance a large and costly supply-side resource such as the Site C Project, the only way to make that resource continue to appear necessary and cost-effective is by curtailing investment in lower-cost DSM.

The next time that BC Hydro’s DSM plans will be subject to review will be as part of its 2018 IRP, and government expects BC Hydro to establish a new DSM Target at that time.243 In the event that the utility continues with the development of the Site C Project, the DSM Target will depend largely on minimizing the energy surplus at the time of

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commissioning of Site C in F2024. Cancelling or suspending the Site C Project would allow BC Hydro to take fuller advantage of the very cost-effective DSM available to the utility.

Barring a change in policy or legislation, the 2018 IRP will not be reviewed or approved by the BC Utilities Commission, and so will very likely avoid rigorous, independent third-party assessment. Furthermore, as we approach 2020, the contradiction between the letter and the spirit of the Clean Energy Act with regard to DSM will become ever more flagrant. Given the ramping down of DSM by BC Hydro since the approval of the 2013 IRP, and the arrival of the large Site C surplus in just a few years, it is likely that DSM will all but disappear from the 2018 IRP.

5.3.2 Capacity-focused demand-side management

In recent years, as a result of a forecasted need for capacity resources in advance of energy resources, BC Hydro has paid increasing attention to DSM measures designed specifically to reduce capacity needs.

In its 2013 IRP, BC Hydro identified two types of capacity-focused DSM with substantial potential:

- Industrial load curtailment: 382 MW of expected capacity savings from large customers who agree to curtail load on short notice to provide BC Hydro with capacity relief during peak periods; and
- Capacity-focused programs: 193 MW in expected capacity savings from programs that leverage equipment (e.g. water heaters, heating, lighting and air conditioning) and load management systems to enable peak load reductions to occur automatically or with intervention through direct load control.

As a result, the potential for capacity-focused DSM savings identified in the IRP totalled 575 MW. However, for planning purposes in its 2013 IRP, BC Hydro entirely disallowed capacity-focused DSM as an available resource, assuming it would deliver zero (0) MW over the next 20 years. In order to further investigate the potential of capacity-focused DSM, BC Hydro made Recommended Action #2 in the 2013 IRP:

Implement a voluntary industrial load curtailment program from F2015 to F2018 to determine how much capacity savings can be acquired and relied upon over the long term. Pilot voluntary capacity-focused programs (direct load control) for

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residential, commercial and industrial customers over two years, starting in F2015.245

In its 2015 Rate Design Application (RDA), filed with the BC Utilities Commission less than a year following the decision to proceed with the Site C Project, BC Hydro stated the following:

In BC Hydro’s view, load curtailment potentially offers a better avenue [than time of use pricing (TOU)] to avoid costly generation capacity resource additions because it is targeted at capacity, is more reliable (particular with aspects of demand control), and in contrast to TOU, load curtailment is dispatchable.246

In other words, BC Hydro acknowledged in the 2015 RDA what it neglected to acknowledge a short time before in the 2013 IRP, namely the substantial benefits of load curtailment for reducing capacity requirements. The utility now also acknowledges that compared to supply-side capacity resources, capacity-focused demand-side management is lower cost and can be developed in smaller increments, has the advantage of shorter lead times and could also relieve local constraints (e.g. regional transmission and/or distribution).247

Since the 2013 IRP, BC Hydro has further advanced its investigation of capacity focused DSM in the form of load curtailment248 and demand response,249 providing additional evidence of the potential efficacy of these approaches for meeting capacity requirements.

Regarding load curtailment, BC Hydro issued a request for proposals in the fall of 2015, in response to which eligible customers proposed amounts of load they were capable of curtailing, to a maximum total requirement of 100 megawatts for up to 36 days per year in aggregate. BC Hydro selected interested proponents, prorating the expected number of curtailment days to a contracted total of 126 MW for 28 days.250 Participants were given day-ahead notice to curtail their load for up to 16 hours per day, up to six consecutive days per week from November 2015 through April 2016. A second Request

249 BC Hydro. 2015. Load Management Demonstration Project. Available at: https://www.bchydro.com/powersmart/business/load-management.html
for Proposals was released in October 2016 for year two of the pilot based on the results of the first year.

With respect to demand response, BC Hydro is conducting a demonstration pilot using wireless load control relays on residential water heaters. BC Hydro is also engaged in researching several other demand response programs. The impacts of these programs, and others under investigation, on demand and participants are yet to be determined. The contribution of capacity-focused DSM now appears to be much larger than the 0 MW presumed in the 2013 IRP.

In its 2015 RDA, BC Hydro also noted the following:

…There is an opportunity to reduce the amount of gas-fired generation that might be required through the development of load curtailment.

This reference to utilizing capacity-focused DSM to reduce the amount of gas-fired generation that might be required in the future is consistent with the direction in the Climate Leadership Plan to move towards 100% clean or renewable electricity. Deferring the need for new gas-fired capacity resources through the use of capacity-focused DSM is a cost-effective approach for BC Hydro compared to the alternative clean and renewable resources available to the utility.

In terms of potential costs, BC Hydro has indicated for its pilot load curtailment program that it is seeking a mix of products with payments summarized in the following table.

<table>
<thead>
<tr>
<th>Number of MW</th>
<th>Duration</th>
<th>Number of Days</th>
<th>Total Hours</th>
<th>Incentive per MW</th>
</tr>
</thead>
<tbody>
<tr>
<td>60</td>
<td>16 hours/day</td>
<td>36</td>
<td>576</td>
<td>$75,000</td>
</tr>
<tr>
<td>40</td>
<td>8 hours/day</td>
<td>36</td>
<td>288</td>
<td>$37,500</td>
</tr>
<tr>
<td>80</td>
<td>4 hours/day</td>
<td>36</td>
<td>144</td>
<td>$18,750</td>
</tr>
</tbody>
</table>

Based on Table 18, the average weighted unit capacity contracted payment to participants in BC Hydro’s load curtailment program is $75/kW-year. BC Hydro’s initial estimate was $57/kW-year, based on the 126 MW contracted in year one of the pilot. That estimate was for up to 28 days of 16 hour/day curtailment (448 hours). Actual costs in the first year of the pilot program were $49/kW-year, lower than the contracted

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capacity value because customers curtailed more than the amount contracted.\textsuperscript{254} The unit capacity costs of capacity-focused DSM are very competitive compared to other capacity alternatives investigated by BC Hydro. The unit capacity cost of natural gas capacity is $115/kW-year,\textsuperscript{255} while the cost of pumped storage hydroelectric is $199/kW-year,\textsuperscript{256} taking into account energy costs, network integration and transmission losses related to these resources.

Based on the identified capacity-focused DSM potential and the results of pilot programs to date, it is anticipated that at least 500 MW of capacity-focused DSM is available to BC Hydro. It is conservatively assumed that these savings would take longer to develop than the five-year period identified in the 2013 IRP, and that the savings could grow from 30 MW in F2018 to 570 MW by F2036. The potential of capacity-focused DSM is included in the scenarios developed in Section 6.3 assessing the conditions under which it is preferable to continue, cancel or suspend the Site C Project.

5.4 Evaluating supply-side resources

In addition to considerable additional energy and capacity available from DSM, BC Hydro also has available to it large quantities of competitively priced and low-emission energy and capacity supply-side resources. In the event that the Site C Project is cancelled or suspended, and despite the contributions from DSM, BC Hydro will eventually need to advance some of these supply-side resources in order to meet future forecasted requirements for energy and capacity.

5.4.1 Energy resources

In its 2013 IRP, BC Hydro evaluated a broad range of potential supply-side energy and capacity resources for inclusion in its resource portfolios. This evaluation considered the technical, financial, environmental and economic development attributes of these resources. Table 19 summarizes the technical and financial attributes of some of these renewable resources, as determined by BC Hydro in its 2013 IRP.

Since the time of the 2013 IRP, some of the resources listed in Table 19 have seen substantial declines in unit energy costs as a result of technological, operational and other advances. In particular, on-shore wind resource costs have declined markedly and their costs are anticipated to continue to decline for the foreseeable future. In addition, utility scale solar PV costs have declined dramatically over the past several years, and


\textsuperscript{255} BC Hydro. July 2016. BC Hydro Fiscal 2017 to Fiscal 2019 Revenue Requirements Application, p. 3-50.

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anticipated future declines could position solar PV as a competitive source of renewable energy available to BC Hydro before the end of the planning period in F2036.

Table 19: 2013 IRP renewable resource technical and financial attributes

<table>
<thead>
<tr>
<th>Supply-side Resource</th>
<th>Dependable Generating Capacity (MW)</th>
<th>Total Energy (GWh/year)</th>
<th>Firm Energy (GWh/year)</th>
<th>UEC at POI(^{257}) ($2013/MWh)</th>
<th>Adjusted Firm UEC(^{258}) ($2013/MWh)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Wood-based Biomass</td>
<td>1,226</td>
<td>9,772</td>
<td>9,772</td>
<td>122 – 276</td>
<td>132 – 306</td>
</tr>
<tr>
<td>Biogas</td>
<td>16</td>
<td>134</td>
<td>134</td>
<td>59 – 154</td>
<td>56 – 156</td>
</tr>
<tr>
<td>MSW Biomass</td>
<td>50</td>
<td>425</td>
<td>425</td>
<td>85 – 184</td>
<td>83 – 204</td>
</tr>
<tr>
<td>Onshore Wind</td>
<td>4,271</td>
<td>46,165</td>
<td>46,165</td>
<td>90 – 309</td>
<td>115 – 365</td>
</tr>
<tr>
<td>Offshore Wind</td>
<td>3,819</td>
<td>56,700</td>
<td>56,700</td>
<td>166 – 605</td>
<td>182 – 681</td>
</tr>
<tr>
<td>Geothermal</td>
<td>780</td>
<td>5,992</td>
<td>5,992</td>
<td>91 – 573</td>
<td>90 – 593</td>
</tr>
<tr>
<td>Run-of-river Hydro</td>
<td>1,149</td>
<td>31,880</td>
<td>24,543</td>
<td>93 – 500</td>
<td>143 – 1,170</td>
</tr>
<tr>
<td>Site C</td>
<td>1,100</td>
<td>5,100</td>
<td>4,700</td>
<td>83</td>
<td>88</td>
</tr>
<tr>
<td>Solar</td>
<td>12</td>
<td>57</td>
<td>57</td>
<td>266 – 746</td>
<td>341 – 954</td>
</tr>
</tbody>
</table>

**On-shore wind**

In the Resource Options Report that forms an appendix to the 2013 IRP, BC Hydro assumed there would be no further declines in real wind costs before F2041, and that the real costs of energy from wind generation would remain equivalent to what they were in F2012. Figure 21 illustrates 18 different projections made in 2011 of the future levelized cost of energy from wind generation.

\(^{257}\) Unit energy cost at the point of interconnection to the integrated transmission system.

\(^{258}\) The costs of resources delivered to the Lower Mainland, including: network upgrades costs; a wind integration cost of $10/MWh; a freshet firm energy adjustment; and a capacity credit of $50/kW-year based on the cost of Revelstoke Unit 6 applied to a resource option that can provide dependable capacity. Values are calculated using a 7% real discount rate for all resources, except the Site C Project calculated at a 5% real discount rate.
The position taken by BC Hydro in its 2013 IRP reflects the single outlier in the graph, namely the *uppermost* horizontal blue line indicating that the cost of wind energy in 2030 would be 100% of its cost in 2011 (i.e. F2012), according to which there would be no future declines in the real cost of wind energy. However, all other industry observers consulted, including the US Department of Energy and the US Energy Information Administration, believed that wind costs would decline by somewhere between 15% and 40% in real terms by 2030, due to technology improvements and other cost reductions. To date, as detailed below, the declines in levelized costs have been on the order of 20%, following closely to the *lowermost* blue line in Figure 21.

BC Hydro now acknowledges that wind energy costs have declined, contradicting the position the utility took in the 2013 IRP. The 2016 RRA now estimates the adjusted unit energy cost of wind at $100/MWh (fiscal 2015$), reflecting a 20% decline in wind costs since the 2013 IRP. These are adjusted unit energy costs that include the cost of transmission losses to deliver energy to the Lower Mainland, network upgrade costs, wind integration costs, among other adjustments. Unadjusted unit energy costs at the point of interconnection would be lower, on the order of $80/MWh. Wind costs are

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marginally higher in BC compared to other jurisdictions due to difficult terrain, mobilization, turbine delivery, and suitable transmission proximity, among other factors.

In its most recent resource options update report, BC Hydro updates its assumptions and methodologies for estimating the unit energy cost of wind,\(^\text{263}\) including:

- 3 MW turbine size (previously 2.3 MW in Class II wind sites)\(^\text{264}\)
- 100 m hub height (previously 80 m)
- 25 year project life (previously 20 years)
- updated capital, operations and maintenance costs

This update is summarized in Figure 22 below, which illustrates that BC Hydro has on the order of 10,000 GWh/year of energy (~3,000 MW of capacity) from onshore wind at less than $100/MWh (7% discount rate), and 6,000 GWh/year of energy (~1800 MW of capacity) at less than $80/MWh (5% discount rate).

In terms of future wind resource costs, BC Hydro believes that the long-term costs of onshore wind will continue to remain unchanged at approximately $100/MWh beyond F2030.\(^\text{265}\) The utility is taking the same perspective it took during the 2013 IRP – the cost of energy from wind resources never declines. On the other hand, Bloomberg New Energy Finance, in its New Energy Outlook 2016, projects that the cost of onshore wind would drop 41% by 2040.\(^\text{266}\) For its part, IRENA projects that the global weighted average levelized cost of energy from wind could fall 26% by 2025.\(^\text{267}\) In a recent elicitation survey of 163 of the world’s foremost wind experts, these experts anticipate a 24% reduction in the levelized cost of energy from onshore wind by 2030 and a 35% reduction by 2050.\(^\text{268}\)


Based on these projections, a further decline of 25% in the levelized cost of energy from wind resources by 2030 is conservative. Considering the information presented by BC Hydro in Figure 22, this would result in about 10,000 GWh/year of energy (~3,000 MW of capacity) at less than $75/MWh at a 7% discount rate, and 6,000 GWh/year of energy (~1800 MW of capacity) at less than $60/MWh at a 5% discount rate. By the late 2020s, it is conservatively anticipated that wind resources can be contracted by BC Hydro at an adjusted unit energy cost of $80/MWh to the end of the planning period in F2036.

**Solar photovoltaic (PV)**

In the 2013 IRP, BC Hydro determined the unit energy cost for a 5 MW utility-scale solar PV system to be $266/MWh for the East Kootenay Region, with costs approximately 5% to 20% higher in the Peace River, Central Interior and Kelly/Nicola regions.²⁷⁰

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In its recent resource options update, BC Hydro revised its estimates of unit energy costs for 13 hypothetical 5 MW utility-scale solar projects located at various locations throughout the Province. The utility’s assumptions and methodologies for estimating the unit energy cost of utility-scale solar, include:

- Project life of 25 years, with a 4 year lead time
- Single axis tracking
- Capacity factor range: 17% to 20%
- $US 1.88/WDC installed

The findings of the update indicate unit energy costs at the point of interconnection for the East Kootenay region of $145/MWh (5% discount rate) and $171/MWh (7% discount rate), with costs in the Kelowna, Peace and Kelly-Nicola regions 5% to 20% higher.  

In Ontario, the IESO recently completed a competitive procurement of utility-scale solar PV projects ranging in size from 1.375 MW to 54 MW, of which the lowest cost was $141.50/MWh. Solar insolation in Kelowna, Kamloops and Cranbrook is very similar to that in Kingston, Toronto and Hamilton. While there are variations between jurisdictions in labour, regulatory and other costs, this provides some additional evidence that the UEC for utility-scale solar PV in British Columbia is currently on the order of $150/MWh in the most cost-effective regions.

With respect to future utility-scale solar PV costs, NREL noted in 2015 that: “analysts project that from 2014-2020, system prices will fall...26% – 36% for utility-scale systems.” The US Department of Energy recently announced its objective of lowering the average levelized cost of energy from utility-scale solar in the United States from $US70/MWh in 2016 to $US30/MWh by 2030, a decline of nearly 60%. Bloomberg New Energy Finance, in its New Energy Outlook 2016 foresees declines of 60% in utility-scale solar PV prices by 2040. IRENA projects that the global weighted

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272 IESO Large Renewable Procurement. Available at: http://www.ieso.ca/Pages/Participate/Generation-Procurement/Large-Renewable-Procurement/default.aspx.
average levelized cost of energy from utility-scale solar PV could decline by 59% by 2025.\textsuperscript{277}

Based on these projections, utility-scale solar PV unit energy costs are set to decline dramatically from current levels. A 60% decline would see unit energy costs drop to $60/MWh in the most cost effective locations in British Columbia and below $80/MWh throughout large areas of the Province within the next 10 to 20 years.

However, these unit energy costs must be adjusted to include the cost of transmission losses to deliver energy to the Lower Mainland, network upgrade costs, and integration costs, among other adjustments. BC Hydro has not provided updated adjusted UECs for utility-scale solar PV since the 2013 IRP. As shown in Table 19, BC Hydro’s estimated the adjustment to be as low as $75/MWh (i.e. $341 – $266/MWh), which compares to $25/MWh for onshore wind (i.e. $115 - $90/MWh). Presuming similar transmission losses and network upgrade costs to integrate wind and solar, the $50/MWh difference requires further explanation. This could be an additional matter for consideration by the BCUC in the event that the Site C Project is referred to the Commission for further review.

Nonetheless, the development of solar resources is not essential to alternative portfolios to the Site C Project; alternative portfolios can instead rely upon the large volumes of low-cost wind energy that is available to BC Hydro. However, to the extent that utility-scale solar PV can provide energy at adjusted unit energy costs lower than that of wind resources, this would further lower the cost of the alternative portfolios that do not contain the Site C Project.\textsuperscript{278}

\subsection*{5.4.2 Capacity resources}

The 2013 IRP also evaluated resources designed specifically to meet capacity requirements. The following table summarizes some of the capacity resources considered by BC Hydro in terms of their unit capacity cost (UCC) at the point of interconnection.


\textsuperscript{278} Comparative evaluation of solar and wind resources must also consider night-time vs. day-time generation, seasonal generation, electric load carrying capacity, and other factors.
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Table 20: 2013 IRP capacity resource technical and financial attributes

<table>
<thead>
<tr>
<th>Capacity Resource</th>
<th>Dependable Generating Capacity (MW)</th>
<th>UCC at POI ($2013/kW-year)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Revelstoke 6 Capacity Upgrade</td>
<td>488</td>
<td>50</td>
</tr>
<tr>
<td>Pumped storage hydroelectric - various</td>
<td>1,000</td>
<td>120</td>
</tr>
<tr>
<td>Pumped storage hydroelectric – Mica</td>
<td>465</td>
<td>100</td>
</tr>
<tr>
<td>Natural Gas SCGT – Kelly Nicola</td>
<td>101</td>
<td>84</td>
</tr>
</tbody>
</table>

**Capacity upgrades**

With the completion of the capacity upgrades at GM Shrum in 2015, capacity upgrades at Revelstoke 6 are now BC Hydro’s lowest cost available capacity resource. BC Hydro is currently undertaking work to advance the Revelstoke 6 project to the environmental assessment stage,\(^{279}\) for an earliest possible in-service date of F2022.\(^{280}\) As a result, it is presumed that this project is developed during the 20-year planning period under all future scenarios. BC Hydro has limited capacity upgrade options following Revelstoke 6.

**Pumped storage hydroelectric**

With respect to pumped storage, BC Hydro recently provided its perspective on the development of this resource:

Revelstoke Unit 6 is a unique low cost capacity option (estimated at $57/kW-yr fiscal 2015$) for BC Hydro available for approximately 500 MW. Beyond that and considering the 100 per cent clean policy from the Climate Leadership Plan which requires new acquisition in the integrated system to be from clean or renewable resources, the next clean generation capacity option would generally be pumped storage facilities which is a step increase in cost (estimated at $199/kW-year fiscal 2015$ including the cost of energy losses in the pump-generation cycle). BC Hydro has estimated the time to commit to and have a pumped storage facility constructed to be about 8 to 10 years.\(^{281}\)

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In its 2013 IRP, BC Hydro identified pumped storage as a potentially useful capacity resource that can respond quickly to variations in system demand. The IRP identified more than 5,000 MW of its lowest-cost pumped storage hydro near to the load centre in the Lower Mainland.\textsuperscript{282}

Of the identified potential sites, a pumped storage facility at the existing Mica generating station was the only facility with seasonal shaping capability (the ability to store water for months, not only hours or days), allowing BC Hydro to better manage its oversupply during the spring freshet. However, pumped storage at Mica need not be limited to seasonal operation, and may also be used to meet weekly or daily capacity requirements.\textsuperscript{283} The total dependable generating capacity of a pumped storage facility at the Mica generating station is 465 MW.\textsuperscript{284}

The Mica site has an updated estimated UCC at the point of interconnection of $109/kW-year (F2015$).\textsuperscript{285} Since the site has been investigated only to a pre-feasibility level, this cost estimate has considerable uncertainty.\textsuperscript{286} In addition, pumped storage hydroelectric is a net user of energy, with efficiency on the order of 70%. This UCC therefore needs to be adjusted to account for these energy inputs as well as for line losses associated with delivering capacity to the main load center in the Lower Mainland. As noted above, BC Hydro recently indicated that its adjusted UCC for pumped storage is $199/KW-year, so this cost is taken as the adjusted UCC for pumped storage at Mica.

The estimates of UCCs at other pumped storage facilities are based only on preliminary surveys and have greater uncertainty in terms of costs and feasibility than a facility at Mica. Given the preliminary nature of these cost estimates, pumped storage hydroelectric, other than at the Mica Generating Station, is not considered in the scenarios developed in Section 6.3 assessing the conditions under which it is preferable to continue, cancel or suspend the Site C Project.

\textsuperscript{283} Hatch. 2010. BC Hydro Pumped Storage at Mica Generating Station Preliminary Cost Estimate, p.2. (Accessed 17 April 2017 at: https://www.bchydro.com/content/dam/hydro/medialib/internet/documents/planning_regulatory/iep_itap/or/appx_10b_pumped_storage_mica_preliminary_cost_estimate.pdf)
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**Simple cycle gas turbines**

Simple cycle gas turbines (SCGTs) are stand-alone natural gas generating stations that are capable of ramping quickly to meet varying loads, and of providing firm energy and dependable capacity. SCGTs have been an integral part of BC Hydro’s planning process.

For example, BC Hydro’s 2013 IRP base resource plan scheduled 400 MW of gas-fired generation by F2020 to meet expected LNG load. The utility’s contingency resource plan also foresaw the addition of 400 MW of SCGTs by F2020 to meet expected LNG, as well as additional SCGTs to meet capacity shortfalls beyond Site C and Revelstoke 6 up to the 93% constraint in the *Clean Energy Act*. BC Hydro’s contingency scenario in the 2013 IRP included 2,058 MW of SCGTs by F2033.

The 2016 RRA updated the unit capacity cost of an SCGT at the point of interconnection at Kelly-Nicola to $79/kW-year. To make the unit capacity costs of an SCGT comparable with other options, the unit capacity costs were adjusted to $115/kW-year, to reflect delivery to the Lower Mainland, to account for energy costs and to include a cost of $30/tonne of CO₂e emissions. The analysis in Section 6.3 concerning whether to continue, cancel or suspend the Site C Project, uses a capacity cost of $84/kWh plus an energy cost, based on the actual amounts generated and the gas price forecasts presented in the IRP.

However, SCGTs also produce greenhouse gas emissions, and the *Clean Energy Act* constrains the potential role of natural gas-fired generation through the following objectives:

- to generate at least 93% of the electricity in British Columbia, other than electricity to serve demand from facilities that liquefy natural gas for export by ship, from clean or renewable resources and to build the infrastructure necessary to transmit that electricity
- to reduce BC greenhouse gas emissions as determined under the *Greenhouse Gas Reduction Targets Act*

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291 As per British Columbia’s Energy Objectives Regulation (B.C. Reg. 234/2012).
More recently, with the release of the Climate Leadership Plan, the Province has signalled its intention to obtain “100% of electricity for the integrated grid from clean or renewable sources, except where concerns regarding reliability or costs must be addressed.” In a recent submission to the BCUC, BC Hydro provide insight into its understanding of this policy:

BC Hydro notes that the Climate Leadership Plan requires 100 per cent clean resources for new greenfield sites in the integrated system unless there is reliability or cost concern. Exceptions on the basis of reliability or cost concerns could be granted through an Integrated Resource Plan. If we encounter a large shortfall of capacity and do not have enough lead time to build new clean generation resources, temporary market reliance and the use of gas resources may need to be considered.

This perspective suggests that BC Hydro continues to be willing to consider the use of SCGTs in those situations where capacity requirements are higher than anticipated, such as in its high-load forecast. How BC Hydro would operate any SCGTs to meet those requirements, considering the constraints in the Clean Energy Act and the Climate Leadership Plan, is less clear.

In the 2013 IRP, BC Hydro presumed that these facilities would operate with an 18% capacity factor, or 1577 hours per year. The effect of this assumption is not inconsequential, as the GHG emissions of SCGTs depend upon both their hours of service and on the frequency of start-ups and shutdowns.

In response to information requests during the 2016 RRA concerning its load curtailment pilot programs, BC Hydro provides insight into how it determines this 18% capacity factor for SCGTs.

We periodically assess system need and have determined that, with the current system and load characteristics, the ability for a load curtailment program to curtail 16-hour peak/day for up to 36 days (totaling 576 hours) anytime over the winter and shoulder months (October through March) would give BC Hydro sufficient capacity and reliability to defer generation capacity and would be assigned a value at 85 per cent of generation capacity annual fixed cost. An additional ability to curtail four peak hours /day over the remaining months would be assigned the remaining 15 per cent of generation value.292

Given the requirements of the Clean Energy Act, the quantity (i.e. in MW) of natural gas capacity that BC Hydro could rely upon is substantially reduced by operating the SCGTs with an 18% capacity factor.

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It appears that BC Hydro is presuming that supply-side capacity resources (i.e. not capacity-focused DSM), developed on its integrated system would need to be available to meet the usual requirements of a peaking plant, namely the winter peak capacity requirements totalling 576 hours, but would also be called upon to operate for four hours almost every other day of the year that is not a holiday or a Sunday (approximately 1000 hours). The use of SCGTs in this manner such that their capacity factor would be 18% is unusual.293

Indeed, the U.S. Energy Information Administration recently reported that the average annual capacity factor, for each of the past 8 years, of all SCGTs in operation in the United States ranged from 4.5% to 6.7%.294 In the case of BC Hydro, though the SCGTs would be available to operate for the 576 hours of the winter peaking season, they would operate somewhat less often as not all days during a winter peak would require 16 hours of peaking capacity. To meet winter peaking requirements only, any SCGTs are presumed to operate for 5% of the time, or 436 hours per year.

For the purposes of the analysis in Section 6.3, evaluating the options of continuing, cancelling or suspending the Site C Project, 18% capacity factors for SCGTs are used in the resource portfolios with the Site C Project, in accordance with BC Hydro’s preferred approach. A 5% capacity factor for SCGTs is used in the portfolios without the Site C Project, limiting the use of the SCGTs to meeting winter peaking requirements.

The upcoming 2018 IRP process provides an opportunity for BC Hydro to further consider the use of SCGTs in its integrated grid.

For context, as shown above in Figure 14, the 5 MT of CO2e emissions from the first 30 years of operations of the Site C Project (i.e. F2024 to F2054), the typical lifespan of an SCGT,295 is equivalent to operating about 800 MW of SCGTs for 436 hours per year (5.0% of the time) to meet BC Hydro’s winter peak capacity requirements. Similarly, the nearly 6 MT of CO2e emissions from the Site C Project during the first 100 years of operations is equivalent to operating about 290 MW of SCGTs to meet BC Hydro’s peaking requirements over that 100 year period.

SCGTs are low capital cost facilities, normally acquired on an as-required basis with an economic life of 30 years. Even if BC Hydro eventually requires some SCGTs, there is a reasonable likelihood that they would be replaced by cost-effective and lower emitting storage before the end of their useful life. Modular energy storage technologies (including lithium-ion batteries, flow batteries, flywheels and other technologies) are evolving and declining rapidly in cost. As these storage technologies also provide

293 U.S. EIA. October 1, 2013. Today in Energy: Natural gas-fired combustion turbines are generally used to meet peak electricity load. (Accessed 17 April 17 at: https://www.eia.gov/todayinenergy/detail.php?id=13191)
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reliable capacity, it is to be expected that they will gradually replace SCGTs when the economics so allow. Indeed, it is quite likely that, by the time the SCGTs included in these plans are actually necessary, it will be economic to acquire storage instead.

For simplicity, the resource portfolios in Section 6.3 to assess whether it is preferable to continue, cancel or suspend the Site C Project model SCGTs as the last-resort modular capacity resource. However, considering the policy direction provided in the Climate Leadership Plan, it is unlikely that they will actually be required. These issues are explored further in Section 6.3.

**Canadian Entitlement under the Columbia River Treaty**

In addition to the energy and capacity resources considered by BC Hydro, the Canadian Entitlement (CE) under the Columbia River Treaty is also potentially available to BC Hydro. Owned by the Province of B.C. and marketed on its behalf by Powerex at Mid-C market prices similar to those shown in Table 13, the Canadian Entitlement is available at a fraction of the cost of energy and capacity from the Site C Project.

Under the Treaty, additional energy and capacity are available to downstream hydroelectric facilities located in the U.S. as a result of reservoirs located in British Columbia. Varying from year to year, in F2014 the CE consisted of 1,330 MW of hydroelectric capacity and 4,425 GWh of energy. These amounts represent “half of the extra power capability at generation facilities in the U.S. that results from the improved water regulation made available by the Columbia River Treaty.” The also represent energy and capacity on par with that provided by the Site C Project, at much lower cost.

However, BC Hydro cannot plan to use the Canadian Entitlement under the Columbia River Treaty because of the self-sufficiency requirement set out in s. 6(2) of the *Clean Energy Act*, which requires that BC Hydro plan to meet all energy needs with in-province generation.

As a result, this hydropower cannot be relied upon by BC Hydro for long-term planning purposes. Thus, it cannot be used to displace far more expensive resources, such as Site C or pumped storage hydro. It should be noted that Section 6(3) of the *Clean Energy Act* does allow the government to authorize BC Hydro by regulation to enter into electricity import contracts otherwise barred under Section 6(2) of the Act.

Subsection 6(3) of the CEA provides an exception to the self-sufficiency requirement found in subsection 6(2). The [Lieutenant Governor in Council] LGIC

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may by regulation authorize BC Hydro to enter into contracts for purposes of not meeting the self-sufficiency requirement.297

In the 2013 IRP, BC Hydro had to assume that the self-sufficiency criterion would remain unchanged throughout its planning period. The JRP reviewing the Site C Project faced a similar constraint. However, the Government of British Columbia is not so constrained, given its executive power to allow exemptions to the self-sufficiency requirement.

The comments of the Joint Review Panel for the Site C Project raised questions as to whether or not this criterion is in the public interest of British Columbians:

Taken literally, this [self-sufficiency requirement of the CEA] means a B.C. disconnected to the outside world, a vision of autarchy truly strange for a province that relies on trade, and a long way from its recent history. (It could also explain the neglect of geothermal opportunities.)

Minor relaxations could mean being connected for reliability or for diversity exchange, which are current practices apparently not condoned by the regulation, or for multi-year balance, all of which seem consistent with the intent if not the drafting of the regulation. …298

The BC Ministry of Energy’s Industrial Energy Policy Review raised the same issue in its Final Report:

As BC Hydro’s surplus diminishes, Government should consider whether a requirement for self-sufficiency is consistent with a long-run approach to least cost electricity prices.299

The Ministry’s formal response suggested that it is open to reviewing this restraint in the future:

BC Hydro is currently in surplus. While not under consideration at this time, this recommendation could be considered as energy forecasts change.300

Once Site C is commissioned, B.C. Hydro will face energy surpluses into the 2030s and potentially much longer. The economic benefit that would flow from the repatriation of the Canadian Entitlement under the Columbia River Treaty would be lost. Powerex


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would also continue to be in the disadvantageous position of selling the Canadian Entitlement at extremely low market prices.

The self-sufficiency requirement was apparently designed in large part to make it impossible to circumvent BC’s clean energy legislation by importing high-GHG power. The Canadian Entitlement, however, consists of hydropower, the environmental costs of which are already borne by British Columbians. Adopting a regulation allowing the import of the Canadian Entitlement could not be seen as compromising BC’s climate policies or its goal of energy self-sufficiency.

However, as a result of the self-sufficiency regulation, the Canadian Entitlement is not considered in the scenarios developed in Section 6.3 assessing the conditions under which it is preferable to continue, cancel or suspend the Site C Project.

5.4.3 BC Hydro purchases of energy and capacity

The opportunity to purchase renewable energy and to renew existing electricity purchase agreements represent additional opportunities to reduce the need for energy and capacity resources delivered by BC Hydro, including from the Site C Project. Whether these opportunities are realized depends on the evolution of the price of energy from these renewables, electricity rates, and BC Hydro’s requirements for energy and capacity. BC Hydro’s current net metering program, standard offer program and existing energy purchase agreements are discussed below.

Net metering

BC Hydro currently offers net metering service to residential and general service customers who generate electricity from clean or renewable resources\(^{301}\) to serve all or a portion of their electricity requirements. Eligible generating facilities must have a nameplate capacity of less than 100 kW. According to BC Hydro, more than 95% of the 900 customers in the net metering program generate energy using solar PV.\(^{302}\)

BC Hydro does not publish estimates of the cost of energy generated from solar PV facilities less than 100 kW in size. The current rates offered for the Ontario IESO feed-in tariff program are used to estimate the current cost of energy from solar PV in the more cost-effective locations in BC. These rates are summarized in Table 21.

\(^{301}\) Includes: biogas, biomass, geothermal heat, hydro, solar, ocean, wind or another clean or renewable energy source.

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Table 21: IESO and BC Hydro price schedules for solar PV

<table>
<thead>
<tr>
<th>Solar PV Type</th>
<th>Project Size</th>
<th>IESO Feed-in Tariff Rate ($/MWh)</th>
<th>BC Hydro Rate Schedule</th>
<th>BC Hydro Rate ($/MWh)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Rooftop</td>
<td>≤ 6 kW</td>
<td>311</td>
<td>Residential</td>
<td>137</td>
</tr>
<tr>
<td></td>
<td>&gt; 6 kW ≤ 10 kW</td>
<td>288</td>
<td>Small General Service</td>
<td>123</td>
</tr>
<tr>
<td></td>
<td>&gt; 10 kW ≤ 100 kW</td>
<td>223</td>
<td>Medium General Service</td>
<td>75</td>
</tr>
<tr>
<td>Non-Rooftop (Ground mount)</td>
<td>≤ 10 kW</td>
<td>210</td>
<td>Small General Service</td>
<td>123</td>
</tr>
<tr>
<td></td>
<td>&gt; 10 kW ≤ 500 kW</td>
<td>192</td>
<td>Medium General Service</td>
<td>75</td>
</tr>
</tbody>
</table>

As shown in the table, current PV costs, as reflected in the prices paid under the Ontario IESO feed-in tariff program, currently exceed the comparable BC Hydro rates paid by consumers for electricity. Thus, there is limited incentive to offset consumption through net metering. Where energy generated exceeds energy consumed, BC Hydro is deemed to have purchased that energy at the net metering rate, currently $99.90/MWh,\(^{305}\) which is also well below the cost to generate energy from solar PV.

As with utility-scale solar PV, residential solar PV costs are expected to continue to decline for the foreseeable future. In 2015, the NREL noted that: “analysts project that from 2014-2020, system prices will fall 16% – 33% for residential systems.”\(^{306}\) The US Department of Energy recently announced its objective of lowering the average levelized cost of energy from residential solar in the United States from US$180/MWh in 2016 to US$50/MWh by 2030, a decline of more than 70%.\(^{307}\)

As solar panel costs decline, the total installed cost of solar PV systems becomes weighted towards balance of system costs.\(^{308}\) These costs now typically account for

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\(^{304}\) Includes 5% rate rider for all rate classes, and goods and services tax.


\(^{308}\) Balance of system costs include those related to grid connection, racking and mounting, electrical installation, inspection, financing and permitting.
more than 70% of total system costs and are much more variable and dependent on local policies and conditions.\textsuperscript{309}

Figure 23 illustrates residential solar cost declines of 40%, 50% and 60% to 2030 for the more cost-competitive regions of British Columbia. These cost declines are compared to Tier 2 residential rates\textsuperscript{310} increasing according to the 10 Year Rates Plan to F2019 and then either 1%, 0.6% or 0% real rate increases thereafter. In the 60% decline scenario, residential solar reaches parity in the cost effective regions of the province by 2025 regardless of rate increases, but in the case of a 40% decline does not reach parity until 2040, even under the high rate increase scenario.

Presuming the 60% price decline scenario is realized, this would apply only to certain regions of the province where solar is most cost effective, which excludes the Lower Mainland. These regions account for not more than 20% of the provincial population,\textsuperscript{311} and would amount to about 400,000 residential customers by 2025.\textsuperscript{312} Of these, only a portion would have suitable solar exposure and be in a position to purchase a 4 kW to 6 kW residential PV system. Installation by 2.5% (10,000) of these customers (0.5% of all residential customers) of an average 5-KW solar system producing 1200 kWh/kW annually would amount to 60 GWh/year (50 MW installed capacity) in offset generation annually beginning in 2025.


\textsuperscript{310} Tier 2 residential rates, which apply after the first 1350 kWh used every two months (8100 kWh/year), are used to reflect the likelihood that those with sufficient rooftop space for solar PV likely consume more than the average of 11,000 kWh/year.


In the case of commercial customers, BC Hydro has three commercial rate classes and some of these customers have the potential to install a more cost-effective ground-mounted solar PV system. Figure 24 illustrates commercial solar cost declines of 40%, 50% and 60% to 2030. These cost declines are compared to small general service rates for rooftop solar, and medium general service rates for ground mount solar, increasing according to the 10 Year Rates Plan to F2019 and then 1%, 0.6% or 0% real increases thereafter. In the case of a 60% cost decline, commercial solar reaches parity by the mid- to late-2020s regardless of rate increases, but in the case of a 40% decline does not reach parity, even under the high rate increase scenario.

Presuming the 60% price decline scenario is realized, this again would apply only to certain regions of the province where solar is most cost effective. These regions are presumed to account for not more than 20% of the ~250,000 commercial customers by 2025. Of these, only a portion would have suitable solar exposure, and high initial capital costs would be expected to somewhat constrain investment, even at 60% lower cost. These customers consume on average about 85 MWh per year, and would not be expected to install systems larger than their consumption if they are participating in a net metering program. Installation by 2.5% (1,250) of these customers (0.5% of all

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commercial customers) of an average 50-KW solar system producing 1200 kWh/kW, or 60 MWh/year, would amount to 75 GWh/year (62.5 MW installed capacity) in offset generation annually beginning in 2025.

Figure 24: Commercial solar PV vs. general service rates

a) Rooftop solar PV (> 10 kW ≤ 100 kW) vs. small general service rates

b) Ground-mount solar PV (> 10 kW ≤ 100 kW) vs. medium general service rates
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In a future scenario where the costs of energy from solar PV continue to decline by 60% or more from today, then total annual incremental generation could be on the order of 135 GWh/year (or 112.5 MW of installed capacity) beginning as early as 2025. For context, Ontario’s Feed-in Tariff program developed about 325 MW per year of installed solar generation capacity beginning in 2011.\(^\text{314}\)

Considering the substantial declines in costs that remain to occur, and that even with a 60% decline in costs distributed solar PV will remain uneconomic in much of the Province, energy delivery from distributed solar PV is likely to remain modest throughout the 20-year planning period.

**Standing Offer Program**

BC Hydro established the Standing Offer Program (SOP) in 2008, and is required to maintain the program pursuant to subsection 15(2) of the *Clean Energy Act*. The purpose of the SOP is to encourage the development of small-scale clean or renewable generation projects (> 100 kW \(\leq 15\) MW), and to streamline the process for these small developers. BC Hydro also offers a Micro-SOP for projects > 100 kW \(\leq 1\) MW for First Nation and community developers.

As of the end of F2017, BC Hydro had signed contracts for 176.8 MW and 648.6 GWh/year under the SOP.\(^\text{315}\) In its 2016 RRA, the utility forecasted 4 MW of dependable capacity and 62 GWh/year of annual energy from the SOP as of F2017, with a gradual increase to 145 MW and 2,045 GWh/year by F2036.\(^\text{316}\) The 2013 IRP introduced an annual incremental energy volume target of 150 GWh/year. The information in the 2016 RRA indicates an expected annual increase of about 8 MW of dependable capacity and 110 GWh/year of energy, which allows for attrition from the 150 GWh/year target.\(^\text{317}\)

The current prices offered under the SOP range from $102.06 MWh/year in the Peace Region to $111.56 MWh/year in the Lower Mainland.\(^\text{318}\) However, in February 2016, BC Hydro announced that, along with the Government of B.C. and Clean Energy BC, it is reviewing these prices and future requirements under the SOP. The basis for this review is the declining cost of renewables and current system requirements for capacity over energy.

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\(^{315}\) BC Hydro SOP: Current Applications. Available at: [https://www.bchydro.com/energy-in-bc/acquiring_power/current_offerings/standing_offer_program/current-applications.html](https://www.bchydro.com/energy-in-bc/acquiring_power/current_offerings/standing_offer_program/current-applications.html)


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Utilities along the Pacific Northwest, including BC Hydro, have an oversupply of energy during the late spring and early summer period (May through to July). We’re also expecting to be in need of new capacity resources in the near and long-term.

We need to focus on acquiring electricity that better fits the needs of the system. For example, dependable capacity is becoming increasingly more important than energy in the mid to long term. As such, we’ll be looking at how to encourage the development of resources that can provide dependable capacity.319

This review and “optimization” of the SOP is in many respects the outcome of the decision to proceed with the Site C Project, which will result in extension of the ongoing energy surplus beyond 2030. Much like the decision to curtail spending on DSM programs, BC Hydro retains considerable discretion to expand or moderate purchases under the SOP, even where those resources might deliver energy and capacity at costs at or below the costs of energy and capacity from the Site C Project, or might avoid the energy surplus created by Site C.

**Electricity Purchase Agreement (EPA) Renewals**

In the 2016 RRA, BC Hydro forecasted 9 MW of dependable capacity and 61 GWh/year of annual energy from EPA renewals in F2017, gradually increasing to 901 MW and 5,515 GWh/year by F2036.320 While these are substantial quantities, they do not represent all the potential dependable capacity and annual energy available to BC Hydro through EPA renewals over the planning period.

In the 2013 IRP, BC Hydro reduced spending on EPAs with Independent Power Producers. Spending reductions were the result of the ongoing energy surplus, and BC Hydro’s desire to reduce short-term costs. BC Hydro identified three potential approaches to cost reductions:

- For projects not yet in operation, defer the commercial operation date, downsize the capacity or terminate the EPA;
- Do not sign any new EPAs; and
- Renew fewer EPAs where contracts are expiring.

In its 2016 RRA, BC Hydro confirmed that it has reached agreements to terminate 14 EPAs, downsize and defer two EPAs, and defer delivery of energy from an additional 11 EPAs. The net result was reductions of 435 MW in nameplate capacity and 1,890 GWh/year of energy through downsizing and terminations, as well as deferral of 2,050 GWh/year from F2015 to F2018. Consistent with the Clean Energy Strategy in the 2013

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IRP, BC Hydro is not proposing to enter into any new EPAs, with the exception of EPAs entered into under the SOP.321

BC Hydro pursues EPA renewals on a cost-of-service basis, and also considers past performance, certainty of continued operation, and system support characteristics.322 As noted in the 2016 RRA, renewal of EPAs with existing facilities has the long-term benefit of delaying future greenfield resources. In addition, BC Hydro notes the following:

Due to the fact that Electricity Purchase Agreement renewals are related to existing projects for which the IPPs' initial capital investment has been fully or largely recovered during the term of the initial Electricity Purchase Agreement, BC Hydro expects to be able to negotiate a lower energy price than the initial Electricity Purchase Agreement. Since the 2013 Integrated Resource Plan, BC Hydro has carried out further analysis of the expected cost of service for existing projects. BC Hydro currently estimates that the renewal volumes in the plan can be acquired at or below $85/MWh (fiscal 2013$) although the relationship between price, volume, contract terms and other non-energy benefits has yet to be established through bilateral negotiations.323

This suggests that, from a levelized cost of energy perspective, planned EPA renewals are on par with the Site C Project. However, this ignores the potential that the EPAs could be renewed on an as-required basis, avoiding the costly energy surplus that would be created by the Site C Project. It is also unclear to what extent this levelized cost is inclusive of capacity benefits or costs related to these renewals, a key consideration given BC Hydro’s need for capacity resources over energy resources.

The potential to renew biomass EPAs is limited by the sustainability and proximity of biomass fuel supply. As a result, BC Hydro assumes renewal of 50% of the energy and capacity from biomass EPAs due to expire prior to the end of the 10 Year Rates Plan, in F2024.324 BC Hydro estimates the average cost of bioenergy EPA renewals to be on the order of $95/MWh,325 which is somewhat higher than the cost of energy from the Site C Project, at $85 to $88/MWh. This suggests that a higher EPA renewal rate for biomass EPAs offers marginal, if any, cost savings compared to the Site C Project.

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In the case of run-of-river hydroelectric EPA renewals, BC Hydro assumes renewal of 75% of these EPAs due to expire prior to the end of the 10 Year Rates Plan, in F2024.\(^\text{326}\) This appears to be a change from the 2013 IRP, which assumed that 75% of these EPAs expiring before F2018 would be renewed, and 100% thereafter.\(^\text{327}\) BC Hydro has estimated the average cost of EPA renewals to be on the order of $70/MWh,\(^\text{328}\) which is materially lower than the cost of energy from the Site C Project.

The remaining 25% of run-of-river hydroelectric EPAs not planned for renewal by BC Hydro may represent an additional low-cost resource available to BC Hydro that is not being fully utilized. This cannot be determined without detailed cost information respecting these EPA renewals. Unfortunately, this information is treated as confidential and not divulged by BC Hydro.

**Implications and opportunities**

Contracting additional resources through net metering, the SOP, and renewing additional EPAs include some cost-effective opportunities that could reduce the need for additional energy and capacity delivered by BC Hydro, including from the Site C Project.

As distributed renewable forms of generation become more cost effective, they will be increasingly used for self-generation, with a commensurate effect on BC Hydro’s requirements for energy and capacity. The timing of this effect depends largely on the extent of cost declines in these resources, but also on future rate increases.

If the Site C Project is developed, and these additional resources do become more cost effective, this could increase and/or prolong the Site C Project energy surplus. BC Hydro and the Provincial Government have several options that could reduce contributions from these resources, even if these additional resources could otherwise provide energy and capacity at lower costs than the Site C Project:

- lower the rates paid, impose additional charges, implement aggregate caps, impose minimum project sizes, or otherwise change the rules to limit contributions under the net metering program, or eliminate the program entirely;
- lower the rates paid, further reduce the aggregate energy contribution, or impose technology or electricity service restrictions (e.g. tender only capacity resources) under the SOP, or eliminate the SOP entirely; and


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- opt not to renew a larger portion of EPAs up for renewal, and delay procurement of new renewable resources indefinitely.

These actions may seem extreme, but many are already being implemented or considered for implementation by BC Hydro in the face of its ongoing energy surplus. The potential actions in relation to the net metering program are strategies already employed in other jurisdictions in the face of increasing contributions from solar PV. Whether these actions represent a least-cost approach to meeting energy and capacity requirements compared to developing the Site C Project cannot be determined without additional information. In particular, a detailed review of the costs of EPA renewals would require access to renewal contracts, which remain confidential. In the event that the Site C Project is reviewed before the BCUC, it will be important to thoroughly review the long-term potential for energy and capacity to be contracted through net metering, the Standing Offer Program, and energy purchase agreements.

5.5 Summary

To summarize, the relevant costs to evaluating continuing, cancelling or suspending the Site C Project are as follows:

- Total expenditures on the Site C Project as of June 30, 2017 are projected to be 1.87 billion, leaving $6.465 billion to be spent;
- Contractual and demobilization costs are estimated at $750 million;
- Costs to maintain the Site C Project in suspension are estimated at $15 million per year;
- Costs to remobilize to continue with the development of the Site C Project are estimated at $200 million, which added to the remaining cost of $6.465 billion results in a cost of $6.665 billion to restart the development of the Site C Project if it becomes cost effective in the future;
- The cumulative effect of BC Hydro’s decisions to moderate DSM during and following the 2013 IRP is more than 3,000 GWh/year and 600 MW by F2024;
- The unit energy cost of energy-focused DSM from the utility cost perspective is on the order of $29/MWh, which compares to $85 to $88/MWh for the Site C Project at the time of the final investment decision;
- BC Hydro is cancelling or scaling back many DSM programs that have utility costs well below the unit energy costs of the Site C Project, at $85 to $88/MWh;
- A total of 126 MW of capacity-focused DSM has been demonstrated in BC Hydro’s pilot programs to date, and an estimated 500 MW of capacity-focused DSM is considered to be feasible by F2030;

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- The cost of capacity-focused DSM is estimated to be on the order of $50/kW-year based on BC Hydro’s pilot programs to date;
- The unit energy cost of on-shore wind resources has declined by 20% since the 2013 IRP and is conservatively projected to decline by another 20% by F2030, resulting in adjusted unit energy costs of $80/MWh by the late 2020s to the end of the planning period in F2036;
- The unit energy cost of utility-scale solar PV is expected to continue to decline on the order of 40% to 60%, resulting in levelized (unadjusted) unit energy costs at or lower than $80/MWh by the end of the planning period in F2036;
- Considering the CO2e emissions of the Site C Project, BC Hydro could develop up to 290 MW of SCGTs operated for a 100-year period to meet winter peak capacity requirements without exceeding the CO2e emissions of Site C; and
- Distributed generation could make the Site C Project less cost-effective by expanding the energy surplus created by the Project; as a result it is reasonable to expect that BC Hydro will continue to moderate and potentially eliminate the net metering program and SOP, and choose to renew fewer EPAs.

These findings are considered in the scenarios developed in Section 6.3 assessing the conditions under which it is preferable to continue, cancel or suspend the Site C Project.
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6. Re-evaluating the Site C Project against the alternatives

6.1 Comparing the alternatives

This Section 6 compares the present value costs of different combinations of demand-side and supply-side resources, including the Site C Project, for meeting BC Hydro’s needs for energy and capacity. In particular, this section reviews the merits of the following options:

a) continue with construction of the Site C Project to completion as scheduled;

b) cancel the Site C Project in order to develop alternative resources; or

c) suspend the Site C Project and develop alternative resources as needed, but leave open the possibility of continuing the Site C Project if circumstances warrant.

In December 2014, the Provincial Government justified the significant adverse environmental effects of the Site C Project on the premise that the project will deliver energy and capacity at lower GHG emissions and lower costs than the available alternatives. However, as summarized earlier in this report, circumstances have changed and new information has become available since the decision to approve the Site C Project.

Specifically, as demonstrated in this report, BC Hydro’s 2012 Load Forecast has collapsed (Section 3.3). As a result, the Site C Project will create a large energy surplus resulting in significant losses (Section 4.4.1), which could be much larger if load growth is lower than forecasted by BC Hydro (Section 4.4.2). It should be noted that BC Hydro has consistently overestimated future requirements for energy (Section 3.2). Though the Site C Project so far remains on budget, the prior experience of BC Hydro and other Crown corporations suggests that cost overruns in large-scale hydroelectric and transmission projects are common (Section 4.3.1) and potentially substantial (Section 4.3.2).

In addition, BC Hydro is dramatically reducing DSM program spending now and into the future, despite the very low costs of energy and capacity from DSM (Section 5.3.1). At the same time, the costs of energy from alternative supply-side resources, particularly wind, have declined substantially since the decision to proceed with the Site C Project, and are forecast to continue to decline in the coming years (Section 5.4.1).

However, the Site C Project also provides dependable capacity in addition to energy. In the absence of the Site C Project, in order to meet its needs for dependable capacity, BC Hydro could develop additional capacity-focused DSM (Section 5.3.2) or a 465 MW pumped storage hydroelectric facility at the Mica Generating Station (Section 5.4.2). It also could operate up to 800 MW of SCGTs for 30 years, or up to 290 MW for 100 years without exceeding the greenhouse gas emissions from the operations of the Site C Project over those respective periods (Section 5.4.2).

BC Hydro will have incurred on the order of $1.87 billion in sunk costs to develop the Site C Project by June 30, 2017 (Section 5.2.1). Cancelling the Site C Project must consider these sunk costs as well as costs related to contract cancellation and
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demobilization (Section 5.2.2). Suspending the Site C Project must consider the costs to carry the sunk costs until a decision is made to continue or cancel the Site C Project (Section 5.2.1), as well as the costs to maintain the project site while in suspension (Section 5.2.3).

Despite these costs, cancelling or suspending the Site C Project could still be the least-cost solution going forward. This Section 6 explores whether or not this is the case, and under what conditions. The section begins with a review of the analysis of alternatives undertaken by BC Hydro in its 2013 IRP (Section 6.2). This is followed by a detailed assessment of the conditions under which it would be preferable to continue, cancel or suspend the Site C Project (Section 6.3). Section 6.4 provides a summary of the model results, while Section 6.5 contemplates additional analyses that could be considered in the event that the Site C Project is referred to the BCUC. The section concludes with a summary of its findings (Section 6.6).

### 6.2 BC Hydro’s analysis of alternatives

The 2013 IRP and the environmental impact statement prepared for the Site C Project make clear that BC Hydro carries out two distinct types of resource analysis for comparing alternatives for meeting the requirements for energy and capacity: a block analysis, and a portfolio analysis.

#### 6.2.1 Block analysis

The block analysis compares the Site C Project to similarly sized blocks of energy and capacity from other sources, and calculates the adjusted unit energy costs for each. The approach has some value for comparing the environmental and socio-economic attributes of different development paths; it allows for direct comparisons in terms of adverse environmental effects, GHG emissions, employment and macroeconomic indicators. But as an approach for comparing the economic attributes of the available alternatives for meeting the energy and capacity requirements of BC Hydro, the block analysis used in the 2013 IRP is fundamentally flawed. In forcing the alternative portfolios to reproduce the energy surplus that the Site C Project would create, it masks the resulting losses.

In its 2013 IRP, BC Hydro compared the adjusted unit energy costs of three blocks of resources designed to provide the same amounts of energy and capacity as the Site C Project (5100 GWh/year and 1100 MW).

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### Table 22: 2013 IRP block analysis – adjusted unit energy costs

<table>
<thead>
<tr>
<th>Blocks</th>
<th>Clean</th>
<th>Clean + Thermal #1</th>
<th>Clean + Thermal #2</th>
<th>Site C</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>Dependable Capacity</td>
<td>Annual Energy</td>
<td>Dependable Capacity</td>
<td>Annual Energy</td>
</tr>
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<td>Supply-side Resources</td>
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<td>GWh/year</td>
<td>MW</td>
<td>GWh/year</td>
</tr>
<tr>
<td>Site C</td>
<td></td>
<td></td>
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<td>5100</td>
</tr>
<tr>
<td>GM Shrum</td>
<td>220</td>
<td>0</td>
<td>220</td>
<td></td>
</tr>
<tr>
<td>Revelstoke 6</td>
<td>488</td>
<td>26</td>
<td>488</td>
<td>26</td>
</tr>
<tr>
<td>Municipal Solid Waste</td>
<td>36</td>
<td>312</td>
<td>36</td>
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<td>Natural Gas (SCGT)</td>
<td>588</td>
<td>924</td>
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<td>1244</td>
<td>5100</td>
<td>1112</td>
<td>5101</td>
</tr>
</tbody>
</table>

| Adjusted UEC ($/MWh)       | 153   | 128                | 130               | 94                 |

The Government of British Columbia, in its Final Investment Decision (FID) for the Site C Project also placed substantial emphasis on the comparison of adjusted unit energy costs between the available alternatives, despite the limitations of this approach.

When considering the impact on ratepayers, the costs of delivering the electricity must be accounted for. In addition, as IPPs are intermittent, the cost of backing them up with firm energy sources (e.g., natural gas) must be included. Also, IPPs do not have the same ability to store energy and take advantage of high prices on the export market, which reduces trade revenues.

Accounting for all of these factors, the final cost to ratepayers is $64 to $67 / MWh\(^3\) for Site C and $110 to $130 / MWh for IPPs.\(^3\)

The intermittency of renewable energy resources and the cost to provide dependable capacity (i.e. "backing them up") are realities that must be considered in a comparative analysis of the alternatives and the Site C Project. These realities are considered in the analysis detailed below in Section 6.3. However, while the BC Government FID notes some potential disadvantages of the alternatives in comparison with the Site C Project, it fails to mention several factors pointing in the opposite direction.

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\(^{334}\) The unit energy costs are based on the firm energy provided, with adjustments made to reflect delivery costs to the Lower Mainland, wind integration costs (where applicable), soft costs and time of delivery of the energy. Capacity costs are added to resource options that do not have dependable capacity. For example, the unit energy cost (excluding sunk cost) of the Site C Project is adjusted for delivery to the Lower Mainland before taking into account a capacity credit. The corresponding adjusted UEC after a capacity credit at the time of the 2013 IRP was $83/MWh.

\(^{335}\) This unit energy cost presumes that the Site C Project is financed in accordance with the 10 Year Rates Plan. See Section 4.2.2.

\(^{336}\) Government of British Columbia and BC Hydro. Site C to provide more than 100 years of affordable, reliable clean power. Backgrounder: Comparing the Options. (Accessed 17 April 2017 at https://news.gov.bc.ca/stories/site-c-to-provide-more-than-100-years-of-affordable-reliable-clean-power)
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First, the quoted unit energy cost of the Site C Project is based on the 10 Year Rates Plan. The actual unit energy cost of the Site C Project as announced in the FID is $85 to $88/MWh. As discussed in Section 4.2.2 above, there is no reason to believe that the Plan, which expires in March 2024, would affect the regulatory treatment of the Site C Project. The 10 Year Rates Plan does not include the Site C Project, and the BC Utilities Commission has yet to determine how the Project will impact rates. The current government has not committed to continue the Plan after it expires and, even if it did make such a commitment, it cannot bind future governments. Moreover, there is no guarantee that future governments will maintain the 10 Year Rates Plan to its scheduled conclusion.

Secondly, as discussed in Section 4.4, if commissioned as planned in F2024, the Site C Project would result in very large energy surpluses, especially in low-load scenarios. The revenues from exporting those surpluses are far less than the annual costs of the Site C Project. The total losses would be on the order of $950 million in the mid-load scenario and exceed $2.7 billion in the low-load scenario.

In addition, considering the collapse of BC Hydro’s load forecast discussed in Section 3.3 and the very low utility cost of additional demand-side management discussed in Section 5.3, pursuing an alternative path has substantial advantages over proceeding with the Site C Project. These advantages go entirely unmentioned in the FID comparison, and include the following:

- **Deferral of costs.** Costs deferred are, to a large extent, costs avoided. In the current low load growth context, and in the absence of proceeding with the Site C Project, BC Hydro would be positioned to defer the development of supply-side resources in favour of lower-cost DSM. This reality contrasts with the situation described in Section 5.3.1, where the decision to proceed with the Site C Project has encouraged the utility to further reduce spending on lower-cost DSM programs in order to limit the future losses from the surplus created by the Site C Project.

- **Modularity and flexibility.** The alternatives to the Site C Project consist of resources that are generally much smaller in size. Development of these resources can occur on a modular basis, only as required to meet load growth, avoiding the losses associated with an energy surplus. In terms of capacity resources, this modularity is more limited beyond capacity-focused DSM and the relatively low-cost Revelstoke 6, as BC Hydro must either choose to develop simple-cycle gas turbines or larger-scale and higher-cost pumped storage hydroelectric. However, the longer these additions can be deferred, the greater the likelihood that low-cost modular storage options will become available.

- **Declining costs.** As noted in Section 5.4.1, the costs of wind and utility-scale solar resources continue to decline dramatically, with numerous projections suggesting that wind power will be available by the late 2020s in BC at adjusted unit energy costs less than $80/MWh.

- **Technology improvements.** By allowing the deferral of resources until they are required, the alternative portfolios can take full advantage of future improvements in demand-side management, generation and energy storage technologies.
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- **Cost overruns.** As discussed in Section 4.3.1, based on the history of large-scale greenfield hydroelectric generation (and transmission) projects developed by BC Hydro and other utilities across Canada, the Site C Project is at risk of substantial cost overruns. The alternative resources that are substitutes for Site C could largely be contracted through independent power producers, transferring the risk of cost overruns to developers and away from ratepayers.

In summary, the block analysis compares four resource portfolios. Site C unavoidably creates an expensive surplus. The other three portfolios are arbitrarily structured to recreate the same costly surplus. The Site C Project is then shown to be superior on the basis of a comparison of adjusted unit energy costs. This ignores the fact that, in reality, none of the alternative portfolios would create the same costly surplus as the Site C Project. **For this reason, the output of the block analysis, a series of adjusted unit energy costs, is not sufficiently informative for comparing the economic attributes of the alternatives.**

### 6.2.2 Portfolio analysis

In order to address the shortcomings of the block analysis, BC Hydro also made use of a portfolio analysis in its 2013 IRP. This analysis was carried out using a series of modeling tools, including System Optimizer, a deterministic optimization model that produces an optimal sequence of generation and transmission resource expansions for a predefined scenario by selecting from the stack of available resources. The model minimizes the present value (PV) of the net cost of meeting a forecast of energy and capacity requirements under average water conditions.

In addition to ensuring that all portfolios satisfy good utility practice, System Optimizer also operates under the constraints imposed by the **Clean Energy Act**, including:

- to achieve electricity self-sufficiency;
- to take demand-side measures to reduce BC Hydro’s expected increase in demand for electricity by the year 2020 (F2021) by at least 66%; and
- to generate at least 93% of the electricity in British Columbia from clean or renewable resources.

The modeling of the alternative portfolios in the 2013 IRP was performed in 2013 real (constant) Canadian dollars for the period F2017 through F2041. The modeling for the 2016 RRA was performed in 2016 real (constant) Canadian dollars for the period F2017 through F2036. These analyses were based on the following assumptions:

- **Inflation rate.** An annual inflation rate of 2% was used in both the 2013 IRP and the 2016 RRA for conversion between real and nominal dollars.

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- **Cost of capital.** The cost of capital used is the weighted average cost of debt and equity. BC Hydro’s weighted average cost of capital (WACC) used in the 2013 IRP and 2016 RRA was 5% real. BC Hydro uses a WACC of 7% real for independent power producers (IPPs). 338

- **Discount rate.** BC Hydro uses 5% and 7% discount rates to calculate levelized unit costs (UECs and UCCs) for BC Hydro and IPP resources, respectively. BC Hydro’s discount rate is used to calculate the portfolio present values since the analysis is from the utility’s perspective.

- **Exchange rate.** The USD to CAD exchange rate used in the 2013 IRP was 0.9693 USD/CAD, reflecting the strength of the Canadian dollar at that time. The exchange rate used in the 2016 RRA increases gradually to 0.82 USD/CAD, and remains at that level until F2036. 339

- **Load resource balances (LRBs).** The LRBs form the base assumption for resource requirements in the IRP portfolio analysis. The LRBs for the 2013 IRP reflect the 2012 Load Forecast and are presented in this report as Figure 10. The LRBs for the 2016 RRA are current to May 2016 and are presented as Figure 11.

- **Market prices.** Costs and revenues of each portfolio are affected by market price assumptions for natural gas, GHGs, electricity and renewable energy credits. The electricity market price assumptions used in the 2016 RRA are presented in Table 13.

- **Resource options.** Chapter 3 of the 2013 IRP contains an extensive list of resource options, and those not eliminated on the basis of cost, policy or other reasons are made available to System Optimizer. A number of generic costs are added to the costs of some resources, including a soft cost adder,340 a wind integration cost adder341 and a network upgrade cost adder.342

The objectives of the *Clean Energy Act*, discussed in Section 2.1.2, include that BC Hydro’s rates “remain among the most competitive of rates charged by public utilities in North America.”343 As such, the comparative present value costs of the portfolios are

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338 BC Hydro’s recent Resource Options Update presents unit energy costs for energy produced by IPPs using both 5% and 7%.
340 This is applied to generic resource options or specific projects that do not have discrete cost estimates which specifically include costs related to mitigation, First Nations, public engagement regulatory review costs. BC Hydro adds 5% to the cost of these resources based on prior experience.
341 Wind integration is highly variable resulting in the need for additional highly responsive generation capacity reserves on the electric system to maintain system reliability and security. Also, the natural variability in wind power generation results in the need to set aside system flexibility to address the potential for wind generation to either under- or over-generate. A wind integration cost adder of $10/MWh is used in the 2013 IRP analysis.
342 This cost adder reflects costs borne by BC Hydro when interconnecting resource options to the bulk transmission system and is added to all resource options except those that have such costs explicitly included in their cost estimates.
343 *Clean Energy Act*, SBC 2010, c22, s.2(f).
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very relevant to the evaluation of the alternatives for meeting energy and capacity requirements.

In its portfolio analysis, BC Hydro models more than sixty different portfolios, of which four portfolios compose its base case:

- A Clean portfolio, without the Site C Project, consisting entirely of resources that meet the definition of clean energy in the *Clean Energy Act*;\(^{344}\)
- A Clean portfolio, with the Site C Project, consisting entirely of resources that meet the definition of clean energy in the *Clean Energy Act*;
- A Clean + Thermal portfolio, without the Site C Project, consisting mostly of resources that meet the definition of clean energy in the *Clean Energy Act*, but including simple cycle gas turbines for capacity up to the limits in the *Clean Energy Act*; and
- A Clean + Thermal portfolio, with the Site C Project, consisting mostly of resources that meet the definition of clean energy in the *Clean Energy Act*, but including simple cycle gas turbines for capacity up to the limits in the *Clean Energy Act*;

The following table illustrates the present value (PV) cost differences determined by BC Hydro in its 2013 IRP, for commissioning the Site C Project as planned in F2024. This table shows that the benefit of the Site C Project in a Clean portfolio was determined to be $630 million, while the benefit in a Clean + Thermal portfolio was determined to be just $150 million.

Table 23: Portfolio present value base case analysis for Site C (in F2024)\(^{345}\)

<table>
<thead>
<tr>
<th>Portfolio Type</th>
<th>PV costs of Portfolios without Site C (M$)</th>
<th>PV costs of Portfolios with Site C (M$)</th>
<th>PV Difference (M$) (Portfolio without Site C minus Portfolio with Site C)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Clean</td>
<td>6,766</td>
<td>6,138</td>
<td>630</td>
</tr>
<tr>
<td>Clean + Thermal</td>
<td>6,030</td>
<td>5,883</td>
<td>150</td>
</tr>
</tbody>
</table>

The $630 million benefit of the Site C Project in the Clean portfolio is largely the result of the relatively high cost of pumped storage hydroelectricity. In the absence of Site C and simple cycle gas turbines (SCGTs), pumped storage hydroelectric meets the bulk of BC Hydro’s capacity needs in the Clean portfolio without Site C. Pumped storage

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\(^{344}\) *Clean Energy Act*, SBC 2010, c22, s.1(1). "*clean or renewable resource*" means biomass, biogas, geothermal heat, hydro, solar, ocean, wind or any other prescribed resource.

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hydroelectric and SCGTs provide most of the capacity in the Clean + Thermal portfolio without Site C.

As noted in Section 3.4.2 dealing with low-carbon electrification in BC, the Province’s Climate Leadership Plan calls for the adoption of 100% clean or renewable electricity, with allowances to address reliability or costs. 346 Due to the high costs of pumped storage hydroelectric, and the lack of another “clean” capacity resource that can provide sufficient capacity at a competitive cost, 347 creation of clean portfolios is considered to be required only in the low-load and mid-load forecasts. The high-load forecast scenarios are considered to raise “concerns regarding reliability or costs” specified in the Climate Leadership Plan, which concerns would justify the development of some natural gas generation for capacity purposes.

Since the time of the 2013 IRP, several circumstances have changed, calling into question the determination that a portfolio with the Site C Project has a lower present value cost compared to an alternative portfolio without the Project:

- **Increased cost of the Site C Project.** At the time of the FID for the Site C Project, the cost of the Site C Project increased from $7.9 billion (nominal) to $8.335 billion (nominal), or $435 million, with a treasury board reserve of an additional $440 million.

- **Reduction in wind costs.** As noted in Section 5.4.1, the unit energy costs of wind resources have declined by about 20% since the 2013 IRP from $125/MWh to $100/MWh. The decline in wind costs disproportionately benefits the portfolios without the Site C Project on the order of $700 million in direct capital cost reductions. 348,349

- **Future declines in wind costs.** Also noted in Section 5.4.1, the unit energy cost of wind resources is conservatively expected to decline from current levels by a further 20% by 2030 when these resources would be required in the portfolios without the Site C Project. This would be an additional benefit to the portfolios without the Site C Project on the order of $600 million in direct costs.

- **Collapse in the load forecast.** The collapse in BC Hydro’s load forecast discussed in Section 3.3 combined with the pending addition of the Site C Project have encouraged BC Hydro to further reduce investment in lower-cost DSM


347 While other potential clean capacity resources, such as lithium-ion batteries, continue to decline in cost, and may become cost-effective by the end of the planning period in F2036, analysis of these potential resources was outside the scope of this report.


programs. However, the collapse in the load forecast can also be seen to open up an opportunity to meet the need for energy and capacity by more aggressively pursuing DSM, and allowing wind and utility-scale solar PV costs to decline further. However, this opportunity is only available by cancelling or suspending the Site C Project.

These factors suggest that the present value cost benefits of proceeding with the Site C Project that were determined in the 2013 IRP have not materialized as predicted. As detailed below, updated alternative portfolios, with costs continuing to decline, are now hundreds of millions of dollars less costly than portfolios with the Site C Project, even when sunk costs and cancellation costs are taken into account.

6.3 Updated analysis of alternatives

The purpose of this updated alternatives analysis was to reconsider the need for the Site C Project. This analysis compares portfolios for meeting BC Hydro’s requirements for energy and capacity in the context of the changed circumstances since the 2013 IRP, as outlined in Section 6.2.2.

The first analysis evaluates whether the decision in December 2014 to proceed with the Site C Project, with the benefit of over two years’ hindsight, was optimal. This analysis, set out in detail in Section 0, was conducted for all of BC Hydro’s future load forecast scenarios – the mid-load, low-load and high-load – as derived from its 2016 RRA. As will become apparent, this analysis demonstrates that if the clock could be turned back to December 2014, a Final Investment Decision not to proceed with the Site C Project would have resulted in savings of $1.4 to $1.7 billion, depending on the future load forecast scenario.

Since that decision was made, however, BC Hydro has spent about $1.87 billion on the Site C Project, and has committed several hundred million more. We estimate that, if the Site C Project were cancelled on June 30, 2017, the total cost to be written off would be on the order of $2.62 billion. In effect, then, the additional cost to complete the Site C Project today is much lower than the cost considered in December 2014. Section 6.3.5 compares the cost of completing the Site C Project against the costs of alternate pathways for meeting energy and capacity requirements, adding the cancellation (or suspension) costs of the Site C Project to all alternative portfolios.

Finally, the analysis explores the implications of several additional scenarios. The first of these considers the implications of a 25% costs overrun for the Site C Project, consistent with the many precedents around the world, across Canada and in recent large-scale BC Hydro projects (Section 6.3.6). The subsequent additional analysis considers the effects of low export market prices (Section 6.3.7), and high market prices (Section 6.3.8), which would increase or decrease, respectively, the losses associated with the energy surplus created by the Site C Project. The following analysis combines the effect of a 25% cost overrun in the Site C Project along with low export market prices (Section 6.3.9). The final analysis (Section 6.3.10) considers the option of...
suspending, but not cancelling the Site C Project, and continuing development of the Project at a later date if it becomes cost effective to do so.

6.3.1 Model design

An Excel-based model was developed to compare the costs of resource portfolios that either continue, cancel or suspend development of the Site C Project. Similar to System Optimizer, this model applies a DSM plan and selects from the available supply-side resources in order to maintain capacity and energy balance, while minimizing present value costs. The model also operates under the constraints imposed by the Clean Energy Act, including those related to achieving self-sufficiency and to generating at least 93% of the electricity in British Columbia from clean or renewable resources. The model analyses are conducted in real 2016 Canadian dollars for the period F2017 through F2036.

Inputs

The model assumptions and inputs are the same as those used previously by BC Hydro in its 2013 IRP, with the following variations:

- **Exchange rate.** The analysis uses the exchange rates provided in Table 13 from the 2016 RRA, which increase gradually over the next few years before stabilizing at 0.82 USD/CAD. This represents a marked change from the 2013 IRP, which forecast a constant exchange rate of 0.9693 USD/CAD from F2014 through F2033.

- **Market prices.** The model makes use of the market price assumptions used in the 2016 RRA and presented in Table 13.

- **Capacity costs:** The model relies on the levelized resource unit capacity costs (UCCs) determined by BC Hydro for capacity resources ($84/kW-year for SCGTs plus energy costs, $199/kW-year for pumped storage hydroelectric at Mica, and $100/kW-year for market purchases). It also attributes capacity sales

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350 While the Clean Energy Act obligation to meet 66% of load growth through DSM is of little relevance, since it is inoperative after 2020, the Option 2 variant described below has a similar, though smaller, effect.


revenues of $37/kW-year for surplus capacity, applied to surpluses greater than 250 MW.

- **Energy costs**: The model relies on the levelized resource unit energy costs (UECs) determined by BC Hydro, with the exception of wind resources, which are presumed to be available at an adjusted UEC of $80/MWh beginning in the late 2020s, as discussed in Section 5.4.1. Energy costs for gas used by SCGTs or, in the high-load scenario CCGTs, is calculated based on the natural gas price forecasts in the 2013 IRP. Energy costs for pumped storage are dealt with as energy requirements in the model, to be met by the available energy resources in the resource stack.

- **Site C Project**: The energy from the Site C Project is presumed to be available in accordance with the load resource balance presented in the 2016 RRA, with 550 MW of capacity available in F2025 and the full 1100 MW by F2026. A small amount of energy (388 GWh) from Site C is available in F2024, 87% of full output in F2025, and full output starting in F2026.

The model evaluates the relative present value cost of meeting future energy and capacity requirements under a number of different scenarios created by adjusting input variables as summarized in Table 24.

The model calculates the present value of the year-by-year costs for resources that are added to the base case, as discussed below in Section 6.3.2, net of revenues from export of surplus energy and capacity. Costs of elements that remain unchanged from the base case scenario are not included in the analysis. Thus, the costs reported below in relation to the various scenarios are only meaningful in comparison to one another, and are not comparable to the total portfolio costs presented above in Table 23.

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Table 24: Model input variables

<table>
<thead>
<tr>
<th>Variable</th>
<th>Alternatives</th>
<th>Description</th>
</tr>
</thead>
<tbody>
<tr>
<td>Load forecast</td>
<td>Low, Mid, High</td>
<td>BC Hydro’s low, mid and high load forecasts as derived from the small gap(^{356}) and large gap(^{357}) scenarios in its 2016 RRA. The high-load forecast scenario encompasses the potential for additional electricity requirements resulting from low-carbon electrification, as discussed in Section 3.4.2. It reflects of additional electricity requirements comparable to the electrification scenario with medium GHG prices and medium natural gas prices shown in Table 6.</td>
</tr>
<tr>
<td>Energy-focused DSM</td>
<td>2016 RRA DSM Plan, 2013 IRP DSM Option 2 updated</td>
<td>BC Hydro’s DSM proposal contained in the 2016 RRA in scenarios with the Site C Project. The updated 2013 IRP Option 2, discussed above in Section 5.3.1, in scenarios without the Site C Project.</td>
</tr>
<tr>
<td>Capacity-focused DSM</td>
<td>Moderate</td>
<td>Following the recent Climate Leadership Plan, moderate capacity-focused DSM (30 MW in F2018, increasing by 30 MW/year to 570 MW in F2036) at a cost of $50/kW-year, is included in all scenarios, as discussed in Section 5.3.2.</td>
</tr>
<tr>
<td>Site C Project</td>
<td>Continuing, Cancelling, Suspending</td>
<td>Continuing with the Site C Project, with costs as described in Section 4.2.1. Cancelling the Site C Project, considering sunk costs of $1.87 billion and $750 million related to contract cancellation and demobilization (5.2.2), amortized over 70 years. Suspending the Site C Project with costs to carry the sunk costs until a decision is made to cancel or complete the Site C Project, as well as suspension costs of $15 million per year to maintain the site (5.2.3) and remobilization costs of $200 million (5.2.4) in the event that circumstances warrant continuing the Site C Project.</td>
</tr>
<tr>
<td>Revelstoke 6</td>
<td>All scenarios</td>
<td>Commissioned in order to minimize net present value costs of each scenario, but not prior to F2022.</td>
</tr>
<tr>
<td>Mica Pumped Storage</td>
<td>All scenarios</td>
<td>Commissioned in order to minimize net present value costs of each scenario, but not prior to F2025.</td>
</tr>
<tr>
<td>Mica 1 to 4 refurbishment</td>
<td>All scenarios</td>
<td>Maintenance outage for five-year period commencing not later than F2024 in all scenarios.</td>
</tr>
<tr>
<td>SCGTs</td>
<td>5%, 18%</td>
<td>A capacity factor of 5% to meet winter peak capacity requirements only, in scenarios without Site C. A capacity factor of 18% to meet winter peak capacity and year-round 4-hour daily peaking requirements in scenarios with Site C.</td>
</tr>
<tr>
<td>CCGTs</td>
<td>Only in high-load forecast scenarios</td>
<td>When large amounts of SCGTs are required, it is more cost-effective to develop CCGTs.</td>
</tr>
<tr>
<td>Market reliance</td>
<td>All scenarios</td>
<td>Short-term reliance of up to 400 MW of capacity and 1,000 GWh/year of energy, consistent with the approach taken by BC Hydro in the 2013 IRP.</td>
</tr>
</tbody>
</table>

\(^{356}\) The Small Gap Scenario is one with the least need for new resources reflecting a low-load forecast combined with low DSM delivery resulting from the fact that a prolonged period of low load growth would likely have BC Hydro scaling back DSM.

\(^{357}\) The Large Gap Scenario is the one with the greatest need for new resources reflecting a high-load forecast combined with lower DSM delivery.
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<table>
<thead>
<tr>
<th>Market prices</th>
<th>Low</th>
<th>Medium</th>
<th>High</th>
</tr>
</thead>
<tbody>
<tr>
<td>2016 RRA market prices as medium market prices, with low and high market prices derived from the spreads between low, mid and high market price forecasts presented in the 2013 IRP.</td>
<td></td>
<td></td>
<td></td>
</tr>
</tbody>
</table>

**Limitations**

The model determines the net present value of the differential costs of each scenario by discounting the year-by-year costs to the present. The model uses BC Hydro’s discount rate of 5% to calculate the portfolio present values, reflecting that the analysis is conducted from the utility’s perspective.

With respect to the discount rates used to calculate the unit costs (UECs and UCCs), the model relies on BC Hydro’s use of 5% and 7% for BC Hydro and IPP resources, respectively. In other words, with the exception of wind resources as discussed in Section 5.4.1, the model relies on the adjusted UECs and UCCs developed by BC Hydro.

The model evaluates different resource options over a 20-year planning period, as BC Hydro did in its 2013 IRP. However, most of the resources will still be in operation at the end of the planning period. This situation creates the possibility of a computational bias, resulting from the exclusion of “end effects”. This is especially true for the Site C Project, which is expected to have an economic life of 70 years, of which only 12 years are included in the analysis period. Since the model reflects the annualized cost and not the total cost of the resources, only those costs incurred in the first twelve years of operations are reflected in the model. The same is true for the additional costs in the “cost overrun” scenario explored later.

While including the end effects for a resource like the Site C Project is straightforward, it would be inappropriate to do so without doing the same for the other resources that will be required in all scenarios with and without Site C after F2036. That would require being able to forecast loads for the same 70-year period. However, forecasting load, prices, technology development, economic conditions and other factors comes with considerable uncertainties. For this reason, BC Hydro limits its load forecasts to 20 years, and so this analysis is limited to the same period.

### 6.3.2 Scenario A – the 2016 RRA

The most recent information made public by BC Hydro is the 2016 RRA, which presents load forecasts and planned resources through F2036. However, the load resource balances in the 2016 RRA do not include sufficient resources to meet energy and capacity requirements through F2036. Thus, the load resource balances (presented above in Figure 11), referred to here as "Scenario A", contain both energy and capacity shortfalls, particularly in the latter years beyond F2032. In other words, they are not “balanced” to the end of the 20-year planning period, as illustrated more clearly in Figure 25.
6.3.3 Scenario B – RRA balanced (the base case)

These shortfalls in energy and capacity result from the fact that the 2016 RRA is not a long-term resource planning document but rather a revenue requirements application for the upcoming three-year operating period. In order to compare the present value costs over a 20-year planning period of continuing, cancelling or suspending the Site C Project, it is necessary to first balance the LRBs contained in the 2016 RRA. This is achieved by making use of the most cost-effective available resources, following the approach set out in the 2013 IRP. Clean resources (primarily wind) are used to meet additional energy needs; as capacity needs are limited and late in the planning period, capacity-focused DSM and market reliance (up to 400 MW) are sufficient to meet them. (The in-service date for Revelstoke is also delayed, compared to the RRA, to avoid creating a capacity surplus.) The RRA balanced LRBs are shown below in Figure 26 in the same planning context (mid-load, including Site C), but with the additional resources needed to maintain adequate energy and capacity until F2036. This “balanced RRA” scenario (Scenario B) is used as a reference case in the analyses that follow.
Resource stacks for the mid, low and high load forecast scenarios are presented in Figure 27, Figure 28, and Figure 29. Similar to the 2013 IRP, these balanced 2016 RRA LRBs include expected LNG, with the Site C Project commissioned in F2024. These scenarios for energy and capacity form the “base cases” against which alternative portfolios that involve cancelling or suspending the Site C Project are evaluated. As summarized in Table 25, the base cases are referred to as Scenario B1 for the mid-load forecast, Scenario B2 for the low-load forecast and Scenario B3 for the high-load forecast. They all reflect BC Hydro’s decision to commission the first generating unit of the Site C Project in F2024.

Table 25: Scenario B – The base case for continuing with the Site C Project

<table>
<thead>
<tr>
<th>Scenario</th>
<th>Load Forecast</th>
<th>Site C</th>
<th>Site C Sunk Costs</th>
<th>Site C Cost Overrun</th>
<th>Market Price Forecast</th>
<th>DSM Option</th>
<th>Capacity-focused DSM</th>
</tr>
</thead>
<tbody>
<tr>
<td>B1</td>
<td>Mid</td>
<td>F2024</td>
<td>Yes</td>
<td>0%</td>
<td>Medium</td>
<td>2016 RRA</td>
<td>Yes</td>
</tr>
<tr>
<td>B2</td>
<td>Low</td>
<td>F2024</td>
<td>Yes</td>
<td>0%</td>
<td>Medium</td>
<td>2016 RRA</td>
<td>Yes</td>
</tr>
<tr>
<td>B3</td>
<td>High</td>
<td>F2024</td>
<td>Yes</td>
<td>0%</td>
<td>Medium</td>
<td>2016 RRA</td>
<td>Yes</td>
</tr>
</tbody>
</table>
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Figure 27: Scenario B1 – Base resource plans with expected LNG (mid-load)

a) Energy

b) Capacity
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Figure 28: Scenario B2 – Base resource plans with expected LNG (low-load)

a) Energy

b) Capacity
Reassessing the Need for Site C

Figure 29: Scenario B3 – Base resource plans with expected LNG (high-load)

a) Energy

b) Capacity
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This base case also includes the DSM plan proposed in the 2016 RRA, as well as capacity-focused DSM starting with 30 MW in F2018 and adding another 30 MW each year, ramping up to 570 MW in 2036.

In the 2013 IRP, BC Hydro attributed 0 MW to capacity-focused DSM through the entire planning period. Since that time, the Climate Leadership Plan was released and specifies an objective of supplying 100% of electricity for the integrated grid from clean or renewable sources, except where concerns regarding reliability or costs must be addressed. This policy directs BC Hydro to pursue capacity-focused DSM, since were BC Hydro not to do so, it would either have to develop SCGTs (low cost, but not a clean or renewable resource), or pumped storage hydroelectric (high cost, but a clean and renewable resource). The development of capacity-focused DSM (low cost, and a clean resource) allows BC Hydro to defer that choice between SCGTs and pumped storage hydroelectric for as long as possible.

Were Scenario B to be developed without capacity-focused DSM, it would either be substantially more costly (due to the need to advance pumped storage hydroelectric) or result in much higher GHG emissions (due to the need to advance SCGTs). This would have the effect of penalizing the base case and therefore making the scenarios without the Site C Project appear to have lower relative present value costs, to produce lower GHG emissions, or a combination of both.

6.3.4 Scenario C – No approval of the Site C Project in 2014

This counter-factual “do over” scenario considers the implications of an initial decision by the Provincial Government not to approve the Site C Project in December 2014. The parameters of Scenario C are listed in Table 26, and reflect the fact that a decision not to approve the Site C Project would have allowed BC Hydro to now continue with an updated DSM Option 2, and to make greater and earlier use of capacity-focused DSM.

Table 26: Scenario C – No approval of the Site C Project in 2014

<table>
<thead>
<tr>
<th>Scenario</th>
<th>Load Forecast</th>
<th>Site C</th>
<th>Site C Sunk Costs</th>
<th>Site C Cost Overrun</th>
<th>Market Price Forecast</th>
<th>DSM Option</th>
<th>Capacity-focused DSM</th>
</tr>
</thead>
<tbody>
<tr>
<td>C1</td>
<td>Mid</td>
<td>Cancel</td>
<td>No</td>
<td>n/a</td>
<td>Medium</td>
<td>Option 2</td>
<td>Yes</td>
</tr>
<tr>
<td>C2</td>
<td>Low</td>
<td>Cancel</td>
<td>No</td>
<td>n/a</td>
<td>Medium</td>
<td>Option 2</td>
<td>Yes</td>
</tr>
<tr>
<td>C3</td>
<td>High</td>
<td>Cancel</td>
<td>No</td>
<td>n/a</td>
<td>Medium</td>
<td>Option 2</td>
<td>Yes</td>
</tr>
</tbody>
</table>

Scenario C reflects the changed circumstances discussed in Section 6.2.2, assuming that the Provincial Government had not approved the Site C Project in December 2014. These changed circumstances include the increased costs of the Site C Project, a substantial decline in wind costs, and the collapse of BC Hydro’s load forecast. Table 27 compares the present values of Scenario C against those of the base case (Scenario B) for the mid, low and high load forecast scenarios at medium market prices.
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Table 27: Cost implications – 2014 approval of the Site C Project (model results)

<table>
<thead>
<tr>
<th>Load Forecast</th>
<th>Market Price Forecast</th>
<th>PV of Scenario C (without Site C) (M$)</th>
<th>PV of Scenario B (with Site C) (M$)</th>
<th>PV Difference (M$) (Benefit or cost of completing the Site C Project)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Mid</td>
<td>Medium</td>
<td>733</td>
<td>2,259</td>
<td>-1,526</td>
</tr>
<tr>
<td>Low</td>
<td>Medium</td>
<td>-3,215</td>
<td>-1,517</td>
<td>-1,698</td>
</tr>
<tr>
<td>High</td>
<td>Medium</td>
<td>5,075</td>
<td>6,498</td>
<td>-1,422</td>
</tr>
</tbody>
</table>

Table 27 demonstrates that:

- under the 2016 mid-load forecast, the decision to proceed with the Site C Project will result in additional costs of $1,526 million dollars, compared to a scenario in which the Project had not been approved;
- under the 2016 low-load forecast, ratepayers would have saved nearly $1,700 million dollars had the Site C Project not been approved; and
- under the 2016 high-load forecast, ratepayers would be ahead by $1,422 million had an approval not been granted for Site C.

Regardless of BC Hydro’s current forecasts of load growth, it now appears likely that the decision to approve the Site C Project will cost ratepayers on the order of $1.4 to $1.7 billion dollars more than had an alternative portfolio of resources been pursued in 2014.

**The road not taken: deferring a decision by two years**

In its 2013 IRP, BC Hydro compared two different in-service dates for the Site C Project (F2024 and F2026). In the mid-load forecast, BC Hydro found that deferring the Project by two years would reduce costs by about $250 million.\(^{358}\) In the low-load forecast, all of the scenarios substantially favoured not proceeding with the Site C Project, by at least $700 million, regardless of the Project’s in-service date.\(^{359}\)

As shown above in Figure 7, for many years prior to the decision to approve the Site C Project, BC Hydro consistently overestimated requirements for energy 10 years in the future, by on the order of 5,400 GWh/year. Moreover, the dramatic increases in BC Hydro’s load forecasts leading up to the decision to approve the Site C Project, presented in Figure 6, contrast sharply with forecasts only a few years earlier.

---


As illustrated in Figure 12, the mid-load forecast has declined by about 5,000 GWh/year since 2012, and now resembles the low-load forecast of that year. **By relying on BC Hydro’s mid-load forecast, and proceeding with the Site C Project as soon as possible in F2024, despite BC Hydro’s history of overstating future electricity demand, the Provincial Government chose to ignore the risks of substantial losses that this strategy would lead to under a low-load scenario.**

### 6.3.5 Scenario D – Cancel the Site C Project

Scenario D considers the implications of cancelling the Site C Project as of June 30, 2017 (i.e. the end of F2017). The parameters of Scenario D are listed in Table 28, reflecting the fact that cancelling the Site C Project would allow BC Hydro to follow an alternative resource path that includes an updated DSM Option 2, capacity-focused DSM and continuing declines in the costs of the alternative resources, particularly wind.

**Table 28: Scenario D – Alternative path after cancellation of the Site C Project**

<table>
<thead>
<tr>
<th>Scenario</th>
<th>Load Forecast</th>
<th>Site C</th>
<th>Site C Sunk Costs</th>
<th>Site C Cost Overrun</th>
<th>Market Price Forecast</th>
<th>DSM Option</th>
<th>Capacity-focused DSM</th>
</tr>
</thead>
<tbody>
<tr>
<td>D1</td>
<td>Mid</td>
<td>Cancel</td>
<td>Yes</td>
<td>n/a</td>
<td>Medium</td>
<td>Option 2</td>
<td>Yes</td>
</tr>
<tr>
<td>D2</td>
<td>Low</td>
<td>Cancel</td>
<td>Yes</td>
<td>n/a</td>
<td>Medium</td>
<td>Option 2</td>
<td>Yes</td>
</tr>
<tr>
<td>D3</td>
<td>High</td>
<td>Cancel</td>
<td>Yes</td>
<td>n/a</td>
<td>Medium</td>
<td>Option 2</td>
<td>Yes</td>
</tr>
</tbody>
</table>

Cancelling the Site C Project as of June 30, 2017 results in $1.87 billion in sunk costs, along with an estimated $750 million contractual and demobilization costs for a total of $2.62 billion. It is presumed that ratepayers repay these costs over a 70-year period beginning in F2025, which is consistent with the expected term for repayment of the costs of a completed Site C Project. It also allows repayment to begin after the 10 Year Rates Plan ends.

Cancelling the Site C Project thus would result in $135 million in annual debt repayment costs for 70 years. These costs are not immaterial, and, since they increase the costs of all scenarios **without** the Site C Project, they tend to counteract the effects of the declining costs of wind energy and the lower load forecast.

Table 29 presents comparisons between cancelling the Site C Project (Scenario D) and continuing with the Site C Project (Scenario B) in the mid, low and high load forecast scenarios at medium market prices.
Reassessing the Need for Site C

### Table 29: Cost implications – cancelling the Site C Project (model results)

<table>
<thead>
<tr>
<th>Load Forecast</th>
<th>Market Price Forecast</th>
<th>PV of Scenario D (without Site C) (M$)</th>
<th>PV of Scenario B (with Site C) (M$)</th>
<th>PV benefit (cost) of completing the Site C Project (M$)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Mid</td>
<td>Medium</td>
<td>1,637</td>
<td>2,259</td>
<td>-622</td>
</tr>
<tr>
<td>Low</td>
<td>Medium</td>
<td>-2,311</td>
<td>-1,517</td>
<td>-794</td>
</tr>
<tr>
<td>High</td>
<td>Medium</td>
<td>5,979</td>
<td>6,498</td>
<td>-518</td>
</tr>
</tbody>
</table>

The findings in this table illustrate that:
- under the 2016 mid-load forecast, it would be $622 million cheaper to proceed down an alternative path by cancelling the Site C Project;
- under the 2016 low-load forecast, ratepayers would be better off by $794 million were the Project to be cancelled; and
- under the 2016 high-load forecast, ratepayers would be better off by $518 million were the Project to be cancelled.

It now appears that cancelling the Site C Project and continuing down an alternative path would save ratepayers on the order of $520 to $800 million, depending on the load forecast.

This means that the Site C Project is not yet “past the point of no return”, regardless of the load forecast scenario. The following subsections will test the additional implications of this conclusion, with respect to two possibilities:
- The Site C Project experiences a cost overrun; and
- Market prices are lower or higher than projected.

6.3.6 Scenario E – Cancel the Site C Project with cost overrun

Scenario E builds on the previous one (Scenario D) by comparing cancellation of the Site C Project against completing it, with the Project incurring a substantial cost overrun. This is a plausible scenario, given that many large-scale Canadian hydro projects built in the last 15 years (with the exception of some Hydro-Québec projects) have incurred significant cost overruns, as have many large transmission projects.

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361 On January 31, 2016, Premier Christy Clark stated in relation to the Site C Project, “I will get it past the point of no return.”

362 The potential that Site C Project costs come in substantially under budget is not analyzed, as it is not considered plausible.
Reassessing the Need for Site C

Table 30 presents the cost overruns of comparable projects in BC and Manitoba. The information in Table 30 was provided above in Section 4.3.1 (Table 12), which also included data on Nalcor Energy projects. The authors view Manitoba Hydro to be the most comparable Canadian utility to BC Hydro, given its recent experience with large-scale hydroelectric and transmission line development. Projects in Manitoba, like the Site C Project, also compete for labour with the fossil fuel industry in Alberta. Hydro Québec has considerably more experience in the past 15 years, having completed several large-scale hydroelectric projects, while Nalcor Energy has considerably less experience, with Muskrat Falls being its first large-scale hydroelectric project since 1985. Nalcor’s service area is much more remote and its labour supply less available making it more vulnerable to cost uncertainties. Based on these factors, and global estimates of an average 27% cost overrun, a 25% cost overrun is considered a conservative scenario for the Site C Project.

<table>
<thead>
<tr>
<th>Hydro Projects</th>
<th>Proponent</th>
<th>Capacity</th>
<th>Total Cost</th>
<th>Overrun</th>
<th>Status</th>
</tr>
</thead>
<tbody>
<tr>
<td>Wuskwatim</td>
<td>Manitoba Hydro</td>
<td>200 MW</td>
<td>$0.9B</td>
<td>$1.6B</td>
<td>$0.7B +78%</td>
</tr>
<tr>
<td>Keeyask</td>
<td>Manitoba Hydro</td>
<td>695 MW</td>
<td>$6.2B</td>
<td>$8.7B</td>
<td>$2.5B +40%</td>
</tr>
<tr>
<td>Bipole III</td>
<td>Manitoba Hydro</td>
<td>500 kV</td>
<td>$3.3B</td>
<td>$5.4B</td>
<td>$2.1B +64%</td>
</tr>
</tbody>
</table>

---


366 Wuskwatim Power Limited Partnership. About the Wuskwatim Generating Station. (Accessed 17 April 17 at [http://www.wuskwatim.ca/project.html](http://www.wuskwatim.ca/project.html))


Reassessing the Need for Site C

<table>
<thead>
<tr>
<th>Scenario</th>
<th>Load Forecast</th>
<th>Site C</th>
<th>Site C Sunk Costs</th>
<th>Site C Cost Overrun</th>
<th>Market Price Forecast</th>
<th>DSM Option</th>
<th>Capacity-focused DSM</th>
</tr>
</thead>
<tbody>
<tr>
<td><strong>E1</strong></td>
<td>Mid</td>
<td>F2024</td>
<td>Yes</td>
<td>25%</td>
<td>Medium</td>
<td>2016 RRA</td>
<td>Yes</td>
</tr>
<tr>
<td><strong>E2</strong></td>
<td>Low</td>
<td>F2024</td>
<td>Yes</td>
<td>25%</td>
<td>Medium</td>
<td>2016 RRA</td>
<td>Yes</td>
</tr>
<tr>
<td><strong>E3</strong></td>
<td>High</td>
<td>F2024</td>
<td>Yes</td>
<td>25%</td>
<td>Medium</td>
<td>2016 RRA</td>
<td>Yes</td>
</tr>
</tbody>
</table>

The parameters of Scenario E are listed in Table 31, reflecting the Site C Project with a 25% cost overrun, medium market prices and BC Hydro’s DSM plan proposed in its 2016 RRA.

Table 31: Scenario E – Site C Project + 25% cost overrun

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Table 32 presents comparisons between cancelling the Site C Project (Scenario D) and completing the Site C Project with a 25% cost overrun (Scenario E) in the mid, low and high load forecast scenarios at medium market prices.

Table 32: Cost implications – Site C Project + 25% cost overrun (model results)

<table>
<thead>
<tr>
<th>Load Forecast</th>
<th>Market Price Forecast</th>
<th>PV of Scenario D (without Site C) (M$)</th>
<th>PV of Scenario E (with Site C) +25% Overrun (M$)</th>
<th>PV benefit (cost) of completing the Site C Project (M$)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Mid</td>
<td>Medium</td>
<td>1,637</td>
<td>2,922</td>
<td>-1,285</td>
</tr>
<tr>
<td>Low</td>
<td>Medium</td>
<td>-2,311</td>
<td>-854</td>
<td>-1,457</td>
</tr>
<tr>
<td>High</td>
<td>Medium</td>
<td>5,979</td>
<td>7,160</td>
<td>-1,181</td>
</tr>
</tbody>
</table>

The findings in this table indicate that a 25% increase in the cost of the Site C Project substantially alters the findings:

- under the 2016 mid-load forecast, it would cost $1,285 million more to continue with the Site C Project that goes over budget by 25% than to cancel the Project and proceed with an alternative portfolio;
- under the 2016 low-load forecast, the benefit to ratepayers of cancelling the Site C Project with a 25% cost overrun totals $1,457 million; and
- under the high-load forecast, the findings indicate that it would be beneficial to ratepayers in the amount of $1,181 million to cancel the Site C Project with a 25% cost overrun.

In the event of a 25% cost overrun, cancelling the Project would save ratepayers on the order of $1.2 to 1.5 billion depending on the load forecast scenario.

A 25% increase in the total Site C Project budget amounts to more than $2 billion (nominal). However, comparing the findings in Table 29 to those in Table 32, the effect on PVs appears to be much smaller, on the order of $700 million (real). This effect results from two factors. First, the cost overrun results in an increase in the future annual costs of the Site C Project that are discounted back to 2016 current dollars. Secondly, since the analysis only extends to F2036, only the first 12 years of the increase in future annual costs (i.e. F2025 through F2036) appear in the calculation. In reality, this increase in Site C annual costs has to be paid for by ratepayers over the 70-year economic life of the Site C Project. Thus, the structure of this analysis tends to underestimate the impact of a significant cost overrun.

6.3.7 Scenarios F and G – Cancel the Site C Project with low market prices

Scenarios F and G are variants of the comparison between Scenario B (base case) and Scenario D (without Site C), but in a future with low export market prices.

In its 2013 IRP, BC Hydro presented forecasts for future export market prices for sales of electricity into the U.S. market at the international border. Low and high price forecasts were also considered by varying the expected price of electricity in the export markets, GHG prices and natural gas prices (the price-setting fuel in the US Northwest).
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BC Hydro updated these price forecasts in its 2016 RRA. Figure 30 presents historical market prices and future export market price scenarios.

**Figure 30: Historical export market prices\(^{378}\) and future scenarios\(^{379}\)**

![Figure 30](image)

The parameters of Scenarios F and G are summarized in Table 33.

**Table 33: Scenarios F and G – The effect of low market prices**

<table>
<thead>
<tr>
<th>Scenario</th>
<th>Load Forecast</th>
<th>Site C</th>
<th>Site C Sunk Costs</th>
<th>Site C Cost Overrun</th>
<th>Market Price Forecast</th>
<th>DSM Option</th>
<th>Capacity-focused DSM</th>
</tr>
</thead>
<tbody>
<tr>
<td>F1</td>
<td>Mid</td>
<td>F2024</td>
<td>Yes</td>
<td>0%</td>
<td>Low</td>
<td>2016 RRA</td>
<td>Yes</td>
</tr>
<tr>
<td>F2</td>
<td>Low</td>
<td>F2024</td>
<td>Yes</td>
<td>0%</td>
<td>Low</td>
<td>2016 RRA</td>
<td>Yes</td>
</tr>
<tr>
<td>F3</td>
<td>High</td>
<td>F2024</td>
<td>Yes</td>
<td>0%</td>
<td>Low</td>
<td>2016 RRA</td>
<td>Yes</td>
</tr>
<tr>
<td>G1</td>
<td>Mid</td>
<td>Cancel</td>
<td>Yes</td>
<td>0%</td>
<td>Low</td>
<td>Option 2</td>
<td>Yes</td>
</tr>
<tr>
<td>G2</td>
<td>Low</td>
<td>Cancel</td>
<td>Yes</td>
<td>0%</td>
<td>Low</td>
<td>Option 2</td>
<td>Yes</td>
</tr>
<tr>
<td>G3</td>
<td>High</td>
<td>Cancel</td>
<td>Yes</td>
<td>0%</td>
<td>Low</td>
<td>Option 2</td>
<td>Yes</td>
</tr>
</tbody>
</table>

\(378\) Northwest Power and Conservation Council. 2016. Seventh Northwest Conservation and Electric Power Plan, Figure 8-1. Historic prices in $2012 US converted to $2016 CAD, and adjusted for wheeling from Mid-C to border by $6.3/MWh. (Accessed 17 April 2017 at: [https://www.nwcouncil.org/energy/powerplan/7/home/](https://www.nwcouncil.org/energy/powerplan/7/home/))

Table 34 presents comparisons between cancelling the Site C Project under low market prices (Scenario G) and completing the Site C Project under low market prices (Scenario F) in the mid, low and high load forecast scenarios.

Table 34: Cost implications – low market prices (model results)

<table>
<thead>
<tr>
<th>Load Forecast</th>
<th>Market Price Forecast</th>
<th>PV of Scenario G (without Site C) Low Market Prices (M$)</th>
<th>PV of Scenario F (with Site C) Low Market Prices (M$)</th>
<th>PV benefit (cost) of completing the Site C Project (M$)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Mid</td>
<td>Low</td>
<td>1,911</td>
<td>2,600</td>
<td>-689</td>
</tr>
<tr>
<td>Low</td>
<td>Low</td>
<td>-901</td>
<td>84</td>
<td>-985</td>
</tr>
<tr>
<td>High</td>
<td>Low</td>
<td>6,030</td>
<td>6,566</td>
<td>-536</td>
</tr>
</tbody>
</table>

These findings indicate that, in the context of low market prices, the benefit of cancelling the Site C Project is increased, compared to that shown in Table 29 regardless of the load forecast. However, the effect of low market prices is not as significant as the effect of a cost overrun:

- under the 2016 mid-load forecast and low market prices, the savings from cancelling the Site C Project would be $689 million, an increase from the $622 million in the context of medium market prices (see Table 29);
- under the 2016 low-load forecast, the benefit to ratepayers of cancelling the Site C Project increases from $794 million with medium market prices to $985 million with low market prices; and
- under the 2016 high-load forecast, the benefit to ratepayers increases from $518 to $536 million.

These increases in the benefits to ratepayers result from the fact that the surplus created by the Site C Project, which would be largest in the low-load forecast and smallest in the high-load forecast, would be sold at lower market prices and yield less revenue. In short, this analysis indicates that:

**In a future context of low export market prices, cancelling the Project would save ratepayers on the order of $540 to $990 million dollars.**

6.3.8 Scenarios H and I – Cancel the Site C Project with high market prices

Scenarios H and I are variants of the comparison between Scenario B (base case) and Scenario D (without Site C), but in a future where the evolution of US electricity market prices follow the high market export price scenario similar to the one described by BC Hydro in the 2013 IRP, modified to reflect changes in market prices since 2012. The parameters of these scenarios are summarized in Table 35.
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Table 35: Scenarios H and I – The effect of high market prices

<table>
<thead>
<tr>
<th>Scenario</th>
<th>Load Forecast</th>
<th>Site C Sunk Costs</th>
<th>Site C Cost Overrun</th>
<th>Market Price Forecast</th>
<th>DSM Option</th>
<th>Capacity-focused DSM</th>
</tr>
</thead>
<tbody>
<tr>
<td>H1</td>
<td>Mid</td>
<td>F2024</td>
<td>Yes</td>
<td>0%</td>
<td>High</td>
<td>2016 RRA</td>
</tr>
<tr>
<td>H2</td>
<td>Low</td>
<td>F2024</td>
<td>Yes</td>
<td>0%</td>
<td>High</td>
<td>2016 RRA</td>
</tr>
<tr>
<td>H3</td>
<td>High</td>
<td>F2024</td>
<td>Yes</td>
<td>0%</td>
<td>High</td>
<td>2016 RRA</td>
</tr>
<tr>
<td>I1</td>
<td>Mid</td>
<td>Cancel</td>
<td>Yes</td>
<td>0%</td>
<td>High</td>
<td>Option 2</td>
</tr>
<tr>
<td>I2</td>
<td>Low</td>
<td>Cancel</td>
<td>Yes</td>
<td>0%</td>
<td>High</td>
<td>Option 2</td>
</tr>
<tr>
<td>I3</td>
<td>High</td>
<td>Cancel</td>
<td>Yes</td>
<td>0%</td>
<td>High</td>
<td>Option 2</td>
</tr>
</tbody>
</table>

Table 38 presents comparisons between cancelling the Site C Project under high market prices (Scenario H) and completing the Site C Project under high market prices (Scenario I) in the mid, low and high load forecast scenarios.

Table 36: Cost implications – low market prices (model results)

<table>
<thead>
<tr>
<th>Load Forecast</th>
<th>Market Price Forecast</th>
<th>PV of Scenario I (without Site C) Low Market Prices (M$)</th>
<th>PV of Scenario F (with Site C) Low Market Prices (M$)</th>
<th>PV benefit (cost) of completing the Site C Project (M$)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Mid</td>
<td>High</td>
<td>1,301</td>
<td>1,856</td>
<td>-555</td>
</tr>
<tr>
<td>Low</td>
<td>High</td>
<td>-3,925</td>
<td>-3,333</td>
<td>-593</td>
</tr>
<tr>
<td>High</td>
<td>High</td>
<td>5,911</td>
<td>6,414</td>
<td>-503</td>
</tr>
</tbody>
</table>

These findings indicate that, in the context of high market prices, the benefit of cancelling the Site C Project decreases compared to that shown in Table 29 regardless of the load forecast. However, the effect of high market prices is not as significant as the effect of a cost overrun:

- under the 2016 mid-load forecast and high market prices, it would be $555 million more expensive to continue than to cancel the Site C Project, a decrease from the $622 million in the context of medium market prices (see Table 29);
- under the low-load forecast, the benefit to ratepayers of cancelling the Site C Project decreases from $794 million with medium market prices to $593 million with high market prices; and
- under the high-load forecast, the benefit to ratepayers decreases from $518 to $503 million.

These decreases in the benefits to ratepayers result from the fact that the surplus created by the Site C Project, which would be largest in the low-load forecast and smallest in the high-load forecast, would be sold at higher market prices and yield more revenue.

In the event of higher than expected market prices, cancelling the Project would save ratepayers on the order of $500 million to $600 million dollars.

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6.3.9 Scenario J – Cancel the Site C Project with cost overrun and low market prices

This scenario builds on the previous scenarios, by combining a 25% cost overrun with low market prices. The parameters of this new Scenario J, together with Scenario G from the Section 6.3.7, are summarized in Table 37.

Table 37: Scenario J – Site C Project + 25% cost overrun + low market prices

<table>
<thead>
<tr>
<th>Scenario</th>
<th>Load Forecast</th>
<th>Site C</th>
<th>Site C Sunk Costs</th>
<th>Site C Cost Overrun</th>
<th>Market Price Forecast</th>
<th>DSM Option</th>
<th>Capacity-focused DSM</th>
</tr>
</thead>
<tbody>
<tr>
<td>J1</td>
<td>Mid</td>
<td>F2024</td>
<td>Yes</td>
<td>25%</td>
<td>Low</td>
<td>2016 RRA</td>
<td>Yes</td>
</tr>
<tr>
<td>J2</td>
<td>Low</td>
<td>F2024</td>
<td>Yes</td>
<td>25%</td>
<td>Low</td>
<td>2016 RRA</td>
<td>Yes</td>
</tr>
<tr>
<td>J3</td>
<td>High</td>
<td>F2024</td>
<td>Yes</td>
<td>25%</td>
<td>Low</td>
<td>2016 RRA</td>
<td>Yes</td>
</tr>
<tr>
<td>G1</td>
<td>Mid</td>
<td>No</td>
<td>Yes</td>
<td>0%</td>
<td>Low</td>
<td>Option 2</td>
<td>Yes</td>
</tr>
<tr>
<td>G2</td>
<td>Low</td>
<td>No</td>
<td>Yes</td>
<td>0%</td>
<td>Low</td>
<td>Option 2</td>
<td>Yes</td>
</tr>
<tr>
<td>G3</td>
<td>High</td>
<td>No</td>
<td>Yes</td>
<td>0%</td>
<td>Low</td>
<td>Option 2</td>
<td>Yes</td>
</tr>
</tbody>
</table>

Table 38 presents comparisons between cancelling the Site C Project under low market prices (Scenario G) and completing the Site C Project with a 25% cost overrun and low market prices (Scenario J) in the mid, low and high load forecast scenarios.

Table 38: Cost implications – Site C Project + 25% cost overrun + low market prices (model results)

<table>
<thead>
<tr>
<th>Load Forecast</th>
<th>Market Price Forecast</th>
<th>PV of Scenario G without Site C + Low Market Prices (M$)</th>
<th>PV of Scenario H with Site C + 25% Overrun + Low Market Prices (M$)</th>
<th>PV benefit (cost) of completing the Site C Project (M$)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Mid</td>
<td>Medium</td>
<td>1,911</td>
<td>3,263</td>
<td>-1,352</td>
</tr>
<tr>
<td>Low</td>
<td>Medium</td>
<td>-901</td>
<td>747</td>
<td>-1,648</td>
</tr>
<tr>
<td>High</td>
<td>Medium</td>
<td>6,030</td>
<td>7,229</td>
<td>-1,199</td>
</tr>
</tbody>
</table>

The findings in Table 38 show that, in the context of a 25% increase in the cost of the Site C Project and low market prices, it would be preferable to cancel the Site C Project. Specifically:

- under the 2016 mid-load forecast, it would be $1,352 million more expensive to continue with the Site C Project;
- under the 2016 low-load forecast, the cost to ratepayers of continuing with the Site C Project would be $1,648 million; and
- under the high-load forecast the cost to ratepayers of continuing with Site C would be $1,199 million.
In the event of a 25% cost overrun in the Site C Project and low market prices, the Site C Project is further from the point of no return. The cost of continuing with the Project ranges from $1.2 billion to $1.65 billion, depending on the load forecast scenario.

A scenario in which both a 25% cost overrun and low market prices occur would be less likely than only one of these scenarios occurring. However, a 25% cost overrun is less than the average cost overrun (43%) of BC Hydro’s most recent three large-scale greenfield transmission projects (see Table 31). Market prices at the BC-US border have also hovered below, and sometimes well below, $40/MWh CAD since 2008, as shown in Figure 30.

6.3.10 Scenario K – Suspend the Site C Project

Scenario K considers the implications of suspending as opposed to cancelling the Site C Project as of June 30, 2017 in order to investigate whether there is an optimal time to develop the Project in the next 20 years. The parameters of Scenario K are listed in Table 39, reflecting the fact that suspending the Site C Project would allow BC Hydro to follow an alternative resource path that includes an updated DSM Option 2, capacity-focused DSM and continuing declines in the costs of wind resources. In the event that the Site C Project becomes cost effective, then it can be taken out of suspension and completed.

Table 39: Scenario K – Alternative path following suspension of the Site C Project

<table>
<thead>
<tr>
<th>Scenario</th>
<th>Load Forecast</th>
<th>Site C</th>
<th>Site C Sunk Costs</th>
<th>Site C Cost Overrun</th>
<th>Market Price Forecast</th>
<th>DSM Option</th>
<th>Capacity-focused DSM</th>
</tr>
</thead>
<tbody>
<tr>
<td>K1</td>
<td>Mid</td>
<td>Suspend</td>
<td>Yes</td>
<td>n/a</td>
<td>Medium</td>
<td>Option 2</td>
<td>Yes</td>
</tr>
<tr>
<td>K2</td>
<td>Low</td>
<td>Suspend</td>
<td>Yes</td>
<td>n/a</td>
<td>Medium</td>
<td>Option 2</td>
<td>Yes</td>
</tr>
<tr>
<td>K3</td>
<td>High</td>
<td>Suspend</td>
<td>Yes</td>
<td>n/a</td>
<td>Medium</td>
<td>Option 2</td>
<td>Yes</td>
</tr>
</tbody>
</table>

Suspending the Site C Project as of June 30, 2017 results in $1.87 billion in sunk costs. It is presumed that ratepayers repay these costs over a 70-year period beginning in F2025, which is consistent with the expected term for repayment of the costs of the Site C Project, and allows repayment to begin after the 10 Year Rates Plan.

In addition, maintaining a suspended Site C Project in a condition where it might be continued if it becomes cost effective adds an estimated $15 million to the annual carrying costs. The result is a total of $112 million in annual carrying costs for up to 70 years, or as long as the Project remains in suspension. These costs are not immaterial, and, since they increase the costs of all scenarios without the Site C Project, they tend to counteract the effects of the declining costs of wind energy and the lower load forecast.

Table 40 presents comparisons between suspending the Site C Project (Scenario J) and continuing with the Site C Project (Scenario B) in the mid, low and high load forecast scenarios at medium market prices. Since suspension carries with it the potential to restart construction of the Site C Project, the optimal date of restarting is also noted in this table.
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Table 40: Cost implications – suspending the Site C Project (model results)

<table>
<thead>
<tr>
<th>Load Forecast</th>
<th>Market Price Forecast</th>
<th>PV of Scenario K (suspended Site C) (M$)</th>
<th>PV of Scenario B (with Site C) (M$)</th>
<th>PV benefit (cost) of completing the Site C Project (M$)</th>
<th>Optimized Date to restart Site C Construction</th>
</tr>
</thead>
<tbody>
<tr>
<td>Mid</td>
<td>Medium</td>
<td>1,392</td>
<td>2,259</td>
<td>-867</td>
<td>2030</td>
</tr>
<tr>
<td>Low</td>
<td>Medium</td>
<td>-2,311</td>
<td>-1,517</td>
<td>-794</td>
<td>After 2036</td>
</tr>
<tr>
<td>High</td>
<td>Medium</td>
<td>5,633</td>
<td>6,498</td>
<td>-865</td>
<td>2027</td>
</tr>
</tbody>
</table>

The findings in this table illustrate that:

- under the 2016 mid-load forecast, there would be a benefit of $867 million to suspending the Site C Project and completing it for a F2030 in-service date, compared to proceeding with the Site C Project for a F2024 in-service date;
- under the 2016 low-load forecast, there would be a benefit of $794 million to suspending the Site C Project and completing it for an in-service date after F2036, compared to proceeding with the Site C Project for a F2024 in-service date; and
- under the 2016 high-load forecast, there would be a benefit of $865 million to suspending the Site C Project and completing it for a F2027 in-service date compared to proceeding with the Site C Project for a F2024 in-service date;

Regardless of BC Hydro’s current forecasts of load growth, suspending the Site C Project in order to develop it at an optimal later date would save ratepayers on the order of $800 to $870 million, depending on the load forecast, compared to completing the Site C Project in F2024.

In addition, it is worth noting that, other than in the low-load forecast, where the Project remains suspended until following F2036, it is preferable to suspend the Site C Project rather than to cancel it. Comparing the findings in Table 40 to those in Table 29, this benefit of suspension over cancellation is $271 million in the mid-load forecast,\(^{380}\) and $352 million in the high-load forecast.\(^{381}\) While these values are not large, they indicate that suspending the Site C Project is preferable to cancelling the Site C Project. However, cancellation and suspension are both superior options to continuing with Site C.

\(^{380}\) i.e. \(-601\text{M} – (-872\text{M}) = 271\)

\(^{381}\) i.e. \(-534\text{M} – (-876\text{M}) = 342\)
### 6.4 Summary of model results

Table 41 provides a summary of the resources for each scenario.

**Table 41: Summary of resources by model scenario**

<table>
<thead>
<tr>
<th>Load Forecast</th>
<th>Scenario</th>
<th>B</th>
<th>C</th>
<th>D</th>
<th>E</th>
<th>F</th>
</tr>
</thead>
<tbody>
<tr>
<td>Low</td>
<td>Site C start date</td>
<td>F2024</td>
<td>Cancel</td>
<td>Cancel</td>
<td>F2024</td>
<td>F2024</td>
</tr>
<tr>
<td></td>
<td>Wind in F2036 (MW)</td>
<td>0</td>
<td>0</td>
<td>0</td>
<td>0</td>
<td>0</td>
</tr>
<tr>
<td></td>
<td>Avg. new gas generation (GWh/y)</td>
<td>0</td>
<td>0</td>
<td>0</td>
<td>0</td>
<td>0</td>
</tr>
<tr>
<td>Medium</td>
<td>Site C start date</td>
<td>F2024</td>
<td>Cancel</td>
<td>Cancel</td>
<td>F2024</td>
<td>F2024</td>
</tr>
<tr>
<td></td>
<td>Wind in F2036 (MW)</td>
<td>715</td>
<td>1181</td>
<td>1181</td>
<td>715</td>
<td>715</td>
</tr>
<tr>
<td></td>
<td>Avg. new gas generation (GWh/y)</td>
<td>0</td>
<td>6</td>
<td>6</td>
<td>0</td>
<td>0</td>
</tr>
<tr>
<td>High</td>
<td>Site C start date</td>
<td>F2024</td>
<td>Cancel</td>
<td>Cancel</td>
<td>F2024</td>
<td>F2024</td>
</tr>
<tr>
<td></td>
<td>Wind in F2036 (MW)</td>
<td>2960</td>
<td>3916</td>
<td>3916</td>
<td>2960</td>
<td>2960</td>
</tr>
<tr>
<td></td>
<td>Avg. new gas generation (GWh/y)</td>
<td>690</td>
<td>226</td>
<td>226</td>
<td>690</td>
<td>690</td>
</tr>
</tbody>
</table>

<table>
<thead>
<tr>
<th>Load Forecast</th>
<th>Scenario</th>
<th>G</th>
<th>H</th>
<th>I</th>
<th>J</th>
<th>K</th>
</tr>
</thead>
<tbody>
<tr>
<td>Low</td>
<td>Site C start date</td>
<td>Cancel</td>
<td>F2024</td>
<td>Cancel</td>
<td>F2024</td>
<td>F2037</td>
</tr>
<tr>
<td></td>
<td>Wind in F2036 (MW)</td>
<td>0</td>
<td>0</td>
<td>0</td>
<td>0</td>
<td>0</td>
</tr>
<tr>
<td></td>
<td>Avg. new gas generation (GWh/y)</td>
<td>0</td>
<td>0</td>
<td>0</td>
<td>0</td>
<td>0</td>
</tr>
<tr>
<td>Medium</td>
<td>Site C start date</td>
<td>Cancel</td>
<td>F2024</td>
<td>Cancel</td>
<td>F2024</td>
<td>F2030</td>
</tr>
<tr>
<td></td>
<td>Wind in F2036 (MW)</td>
<td>1181</td>
<td>715</td>
<td>1181</td>
<td>715</td>
<td>0</td>
</tr>
<tr>
<td></td>
<td>Avg. new gas generation (GWh/y)</td>
<td>6</td>
<td>0</td>
<td>6</td>
<td>0</td>
<td>0</td>
</tr>
<tr>
<td>High</td>
<td>Site C start date</td>
<td>Cancel</td>
<td>F2024</td>
<td>Cancel</td>
<td>F2024</td>
<td>F2027</td>
</tr>
<tr>
<td></td>
<td>Wind in F2036 (MW)</td>
<td>3916</td>
<td>2960</td>
<td>3916</td>
<td>2960</td>
<td>2120</td>
</tr>
<tr>
<td></td>
<td>Avg. new gas generation (GWh/y)</td>
<td>226</td>
<td>690</td>
<td>226</td>
<td>690</td>
<td>104</td>
</tr>
</tbody>
</table>

B = The base case  
C = No approval of the Site C Project in 2014  
D = Cancel the Site C Project  
E = Cancel the Site C Project with cost overruns  
F = The base case with low market prices  
G = Cancel the Site C Project with low market prices  
H = The base case with high market prices  
I = Cancel the Site C Project with high market prices  
J = Cancel the Site C Project with low market prices  
K = Suspend the Site C Project

Wind development varies substantially under the various scenarios. No new wind resources are developed in the low-load forecast scenarios, as additional DSM or the development of the Site C Project is able to meet requirements for the duration of the planning period. In the medium and high-load forecasts, wind resources are developed in all scenarios except the scenario where the Site C Project is suspended (Scenario K).
in the mid-load forecast. In this instance, DSM and other resources meet requirements until the Site C Project comes on-line in F2030.

**All alternative scenarios considered have very low greenhouse gas emissions.**

With respect to natural gas generation resources, no natural gas resources are developed in the low-load forecast scenarios, as DSM meets all additional requirements. In the mid-load forecast, the portfolios without the Site C Project develop SCGTs only in F2036, the last year of the planning period, to meet winter peak requirements. In terms of capacity, 186 MW are developed producing 81 GWh/year of energy. The total annual GHG emissions from the operation of these SCGTs would be about 0.039 Mt CO₂e, for a total of 1.16 MT CO₂e emissions over 30 years, or 3.9 MT CO₂e emissions over 100 years. This compares to the operations of the Site C Project, which would produce 5 MT of CO₂e emissions over 30 years, and 6 MT of CO₂e emissions over 100 years.

In the high-load forecast scenarios, considerably more gas is developed in all scenarios, beginning in F2021 in the portfolios without the Site C Project, and in F2029 in the portfolios with the Site C Project. A more rapid introduction and ramp up of capacity-focused DSM could delay the need date for these resources. The average annual generation from SCGTs is higher in the portfolios with the Site C Project than in those without the Site C Project. This is the outcome of BC Hydro’s approach to operating SCGTs at 18% capacity factors. By the end of the planning period, the scenarios with the Site C Project develop 1,217 MW of SCGTs while those without the Site C Project develop 1,038 MW.

Though pumped storage hydroelectric generation at the Mica Generating Station was included in the modelling, the facility did not start (DNS) operating in most of the scenarios. Only in the high-load forecast without the Site C Project was this resource selected in F2036. This explains the lower capacity of SCGTs in the portfolios without the Site C Project in the high-load forecast scenario at the end of the planning period. As shown in Table 42 below, the portfolios without the Site C Project all had a cost advantage of more than $500 million over the portfolios with the Site C Project. This cost advantage could be applied to advancing pumped storage to an earlier date in order to further lower GHG emissions.

The percentage of energy coming from non-clean resources remains below the 7% maximum prescribed in the Clean Energy Act for all of the forecast scenarios.

### 6.5 Additional considerations

The modelling exercise described above assessed the relative benefits and costs of continuing, cancelling or suspending the Site C Project under a number of different scenarios. These scenarios included:

- low, mid, and high load forecasts;
- the Site C Project on budget or with a 25% cost overrun;
- low, medium, and high export market prices;
- a combination of a cost overrun and low market prices; and
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- suspending the Site C Project in order to resume construction in the future, should circumstances so warrant.

The above scenarios address the most important issues, but are not exhaustive. With additional time and resources, other scenarios could be developed and analyzed to assess additional factors. In the event that the Site C Project is suspended and referred to the BCUC for additional review, additional analyses could consider the following:

- **Wind prices.** This report finds that the adjusted unit energy cost of wind is conservatively anticipated to decline by an additional 20% by 2030. Greater or lesser declines could be assessed to determine the effects on the portfolio costs and benefits.

- **Capital and operating costs.** With the exception of BC Hydro’s assumptions regarding the future costs of energy from wind resources, this research has accepted BC Hydro’s estimates of the costs to develop and operate various demand-side and supply-side resources. A review and sensitivity analysis of these cost estimates before a public utility board, such as the BCUC, is usual practice prior to approval of a project of the size and significance of the Site C Project. In the event that further review is undertaken by the BCUC, the costs of the demand-side and supply-side resources should receive particular scrutiny.

- **Site C Project cost overruns.** The modelling exercise considers only the potential for a 25% cost overrun, which is consistent with other large-scale hydroelectric development across Canada and around the world. However, some hydroelectric and transmission projects in operations and under construction in Canada, including BC Hydro projects, have had much higher cost overruns. An appropriate time and context to undertake such a review would be in a hearing before the BC Utilities Commission.

- **Storage technologies.** This report was not able to assess the potential implications of significant further declines in the cost of battery and other forms of energy storage. These resources could be added to the resource stack to determine whether they could become cost-effective within the 20-year planning period in order to assess what impact, if any, they would have on the findings.

- **Geothermal.** In its 2013 IRP, BC Hydro estimated that the province has available on the order of 500 MW and 4,000 GWh/year of geothermal resources at a unit energy cost of $100/MWh.\(^{382}\) Half of this amount is located in the Lower Mainland, the primary load center in the Province. However, due to its high initial capital costs to locate and developed suitable resources, no projects have been developed to date in British Columbia. For these reasons, geothermal resources were not considered in the analysis in this report. Any future analysis should seek to resolve cost uncertainties, and look to other jurisdictions where

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geothermal resources have been successfully developed. Geothermal could be particularly relevant to a decision to cancel versus suspend the Site C Project if these matters can be resolved in the next few years. In the event that further review of the Site C Project is undertaken by the BCUC, geothermal potential should receive particular attention, as recognized by the JRP in its final report.

- **Financial parameters.** Additional scenarios could theoretically be developed to test the effect of different financial parameters, including discount rates, cost of capital, exchange rates, etc. In general, these parameters are built in to the unit energy costs and unit capacity costs of the various resources used in the analysis, and there may not be sufficient information available on the public record to undertake this kind of financial sensitivity analysis.

- **Macroeconomic issues.** The analysis of alternatives could be broadened to consider key macroeconomic considerations, including employment, government revenue and government debt.

- **Macroenvironmental issues.** The analysis in this report considers the social costs of GHG emissions. However, no costs are allocated with respect to the residual environmental effects of the various alternative portfolios, indirectly assigning zero value to these externalities. In general, this approach tends to favour portfolios with the Site C Project considering the extent of its significant adverse environmental effects and its effects on ecosystem services. While some of these effects are quantifiable (e.g. habitat loss), others are more qualitative (e.g. visual impacts, loss of use).

- **Social issues.** The consequences, in terms of impacts and benefits, of the alternative portfolios for Indigenous, local and provincial populations also merit consideration in a fuller analysis of the alternative portfolios. This could include consideration of local, regional and provincial benefits, impacts on Indigenous peoples and relations with government, as well as the legacy effects of the portfolios for future generations.

### 6.6 Summary of findings

The modeling exercise investigated the following options:

- a) continue with construction of the Site C Project to completion as scheduled;
- b) cancel the Site C Project in order to develop alternative resources; or
- c) suspend the Site C Project and develop alternative resources as needed, but leave open the possibility of continuing the Site C Project if circumstances warrant.

Each of the scenarios was developed under the constraints imposed by the *Clean Energy Act*, including those related to achieving self-sufficiency and to generating at least 93% of the electricity in British Columbia from clean or renewable resources. The operational GHG emissions of all resources, including the Site C Project were included in the analysis.

Table 42 summarizes the net present value benefit (cost) of continuing with the Site C Project under the various scenarios. **These results indicate that it was not prudent to proceed with the Site C Project, and it remains imprudent to continue with it.**
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Regardless of the load forecast scenario, it would be preferable to suspend or cancel the Site C Project. If market prices are lower than anticipated, and particularly if there is a 25% cost overrun, the losses associated with continuing the Site C Project would be much higher.

Table 42: Cost implications – summary of model results ($million)

<table>
<thead>
<tr>
<th>Load Forecast</th>
<th>No approval of Site C in 2014</th>
<th>Cancel Site C</th>
<th>Cancel Site C with 25% cost overrun</th>
<th>Cancel Site C with low market prices</th>
<th>Cancel Site C with low market prices</th>
<th>Cancel Site C with cost overrun and low market prices</th>
<th>Suspend Site C</th>
</tr>
</thead>
<tbody>
<tr>
<td>Low</td>
<td>-1,698</td>
<td>-794</td>
<td>-1,457</td>
<td>-985</td>
<td>-593</td>
<td>-1,648</td>
<td>-794</td>
</tr>
<tr>
<td>Mid</td>
<td>-1,526</td>
<td>-622</td>
<td>-1,285</td>
<td>-689</td>
<td>-555</td>
<td>-1,352</td>
<td>-867</td>
</tr>
<tr>
<td>High</td>
<td>-1,422</td>
<td>-518</td>
<td>-1,181</td>
<td>-536</td>
<td>-503</td>
<td>-1,199</td>
<td>-865</td>
</tr>
</tbody>
</table>

In summary, our findings are: 1) The decision to approve the Site C Project in 2014 will cost ratepayers on the order of $1.4 to $1.7 billion dollars more than had an alternative portfolio of resources been pursued at that time. 2) Our analysis indicates that cancelling the Site C Project as of June 30, 2017 would save between $500 million and $1.65 billion, depending on future conditions. 3) Suspending the Site C Project is preferable to cancelling the Project by up to $350 million. Both cancelling and suspending are preferable to continuing with the Site C Project.

Our recommendation is: Suspend the Site C Project, and refer the Project to the BC Utilities Commission for a full review.
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ACRONYMS

AESO Alberta Electric System Operator
BCUC British Columbia Utilities Commission
CCGT Combined cycle gas turbine
CE Canadian Entitlement under the Columbia River Treaty
CEAA Canadian Environmental Assessment Act
CO₂e Carbon dioxide-equivalent
DSM Demand-side management
EIS Environmental Impact Statement
FID Final Investment Decision
IPP Independent Power Producer
IRP Integrated Resource Plan
JRP Joint Review Panel
PV Present value
RDA Rate Design Application
RRA Revenue Requirements Application
SCGT Simple cycle gas turbine
TOU Time-of-use
TRC Total resource costs
UC Utility costs
UCC Unit Capacity Cost
UEC Unit energy cost
WACC Weighted average cost of capital
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GLOSSARY383

**Alberta Electric System Operator** As an independent system operator, the AESO leads the operation and planning of Alberta’s interconnected power system. AESO also facilitates Alberta’s competitive wholesale electricity market.

**Base Resource Plan** BC Hydro’s proposed action plan for meeting its current and future customers’ electricity needs on a reliable and cost-effective basis.

**Billed Sales** The amount of electricity billed. Because bills are produced after the electricity has been delivered, monthly billed sales lag monthly delivery of electricity.

**British Columbia Utilities Commission** An independent regulatory agency of the provincial government operating under and administering the Utilities Commission Act. The BCUC regulates BC Hydro’s domestic supply and rates and the safety and reliability of the BC Hydro system, as well as operating, management and administrative costs, and also assesses concerns from ratepayers regarding BC Hydro’s service.

**Canadian Entitlement** The Canadian 50 per cent share of the computed increase in downstream energy and capacity benefits on the Columbia River in the U.S. due to the construction and coordinated operation of Duncan, Keenleyside and Mica storage dams in Canada, as provided for under the Columbia River Treaty (1964).

**Capacity** The power produced or demanded at a particular time, usually measured in kilowatts (kW) or megawatts (MW).

**Capacity Factor** The ratio of the average annual power output to the rated power output of electricity generating plants.

**Certificate of Public Convenience and Necessity (CPCN)** A certificate/permit issued by a public body, such as the B.C. Utilities Commission, that is charged with the supervision of public facilities, e.g., transmission carriers or public utilities. The certificate authorizes the holder of the permit to operate, or construct a public facility (such as a generating plant or transmission facilities) within a particular area. The issuance of the certificate is made after application, notice and hearing.

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**Clean Energy Act (CEA)** The legislation that sets the foundation for electricity self-sufficiency, job creation and reduced greenhouse gas emissions. The Act also describes the consideration of investments in clean, renewable energy across the province.

**Clean or Renewable Energy** Defined by the Clean Energy Act as including biomass, biogas, geothermal heat, hydro, solar, ocean, wind or other prescribed resources.

**Climate Leadership Plan** A policy document produced by the B.C. Government that describes actions that will be undertaken as government moves to its target of reducing greenhouse gas emissions by 33 per cent below 2007 levels by 2020 and 80 per cent by 2050.

**CO₂e** Carbon dioxide-equivalent. A unit that measures the climate change potential of each of the six greenhouse gases identified in the Kyoto Protocol.

**Columbia River Treaty** A treaty ratified in 1964 between Canada and the U.S. that enabled storage reservoirs to be built and operated in British Columbia to regulate Columbia River flows to the U.S. for power production and flood control.

**Combined Cycle Gas Turbine** The combination of combustion and steam turbines to generate electricity from two thermodynamic cycles. Exhaust gases from a combustion turbine flow to a heat recovery steam generator (HRSG) that produces steam to power a steam turbine, resulting in higher thermal efficiency than achievable by operating the combustion or steam turbines individually.

**Conservation** Reducing the level of energy service to reduce energy consumption. For example, turning off unused lights.

**Contingency Resource Plan** A plan that identifies alternative sources of supply and transmission components that could be required should the Base Resource Plan not materialize as expected.

**Dependable Capacity** The maximum generator output that can be reliably supplied coincident with the system peak load, taking into account the physical state and availability of the equipment, and on water or fuel constraints.

**Demand-side Management (DSM)** Activities that occur on the demand side of the revenue meter and are influenced by the utility. DSM activities result in a change in electricity sales. Past DSM savings include incremental load displacement and energy efficiency savings. Note that BC Hydro’s historical sales include the impact of DSM savings realized up to that year.

**Discount Rate** A rate used to determine the present value of cash flows (expenses and revenues) that will occur over a period of time, reflecting the cost of capital.
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Dispatchable A resource whose output can be adjusted to meet various conditions including fluctuating customer demand, weather changes, outages, market price changes and non-power considerations.

Distribution Delivery of electricity to retail customers, generally at voltages lower than 69 kV.

Efficiency The effective rate of conservation of a natural resource (e.g., electricity) to usable energy; the effective rate of conversion of electricity to an end use (e.g., heating).

Elasticity The proportionate change in a dependent variable (e.g. electricity consumption) divided by the proportionate change in a specified independent variable (e.g. electricity price). A dependent variable is highly elastic with respect to a given independent variable if the calculated elasticity is much greater than one. The dependent variable is inelastic if the elasticity is less than one.

Electricity Purchase Agreement (EPA) The contract that defines the terms and conditions by which BC Hydro purchases electric energy from Independent Power Producers.

Energy The amount of electricity delivered or consumed over a certain time period, measured in multiples of watt-hours. A 100-watt bulb consumes 200 watt-hours in two hours.

Energy Efficiency (EE) A reduction in energy usage to provide the same level of energy service, such as lighting, cooling or motor torque.

Final Investment Decision (FID) The decision made in December 2014 by the BC Government to approve the Site C Project and proceed with construction.

GHG Emissions Refers to GHG emissions per unit of electrical production, measured in units of tonnes of CO₂e/GWh.

Gigawatt-hour (GWh) A measure of electrical energy, equivalent to one million kilowatt-hours. (See Units of Measure.)

Greenhouse Gases (GHG) Greenhouse gas – any of the atmospheric gases that contribute to climate change such as water vapour, methane, or carbon dioxide

Gross Domestic Product (GDP) A measure of the total flow of goods and services produced by the economy over a specified time period, normally a year or quarter. It is obtained by valuing outputs of goods and services at market prices (alternatively at factor cost), and then aggregating the total of all goods and services.

Independent Power Producer (IPP) A non-utility-owned electricity generating facility that produces electricity for sale to utilities or other customers.
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**Integrated Resource Plan (IRP)** The document describing BC Hydro’s long term plan to meet customers’ needs using existing and new resources and demand-side measures.

**Integrated system** That portion of the BC Hydro electricity system that is connected as one whole by a high voltage transmission grid.

**Integrated system peak** includes the peak requirements for BC Hydro’s distribution and transmission customers in its service territory; sales to Other Utilities; and system transmission and distribution losses.

**Intermittent Resource** A source of energy that has varying output due to natural changes, and is not dispatchable; can also be referred to electricity supply that fluctuates or is not available at all times.

**Kilowatt (kW)** One thousand watts; the commercial unit of measurement of electric power. A kilowatt is the flow of electricity required to light ten 100-watt light bulbs.

**Kilowatt-hour (kWh)** A measure of electrical energy, equivalent to the energy consumed by a 100-watt bulb in 10 hours. (See Units of Measure)

**Liquefaction** The process by which natural gas is converted to liquid through refrigeration. Liquefaction facilities are important infrastructure in the LNG production and transportation process. Liquefaction reduces the volume by approximately 600 times, making it more economical to transport between continents in specially designed ships.

**Liquefied Natural Gas (LNG)** is natural gas that has been converted temporarily to liquid form for ease of storage or transport. This process involves refrigeration, and requires no chemical transformations.

**Load** The total amount of electrical power demanded by the utility’s customers at any given time, typically measured in megawatts.

**Load Curtailment** A reduction in demand as a result of demand-side measures or a decrease in generation output.

**Load Displacement** Projects that involve the installation of self-generation facilities at customer sites, with the electricity generated being used on-site by the customer, with a resultant decrease in the purchase of electricity from BC Hydro.

**Load Forecast** The expected load requirements that an electricity system will have to meet in future years.

**Load Forecasting** The process to determine the expected amount of electricity required to meet customer needs in future

**Load-Resource Balance (LRB)** The difference between B.C. Hydro’s Load Forecast and existing and committed resources available to meet the load.
Reassessing the Need for Site C

Megawatt (MW) A unit used to measure the capacity or potential to generate or consume electricity. One MW equals one million watts. (See Units of Measure.)

Megawatt-hour (MWh) A measure of electrical energy, equivalent to 1,000 kWh. (See Units of Measure)

Mid-Columbia (Mid-C) Wholesale electricity trading hub located in the U.S. Pacific Northwest.

Natural Conservation The changes in end use efficiency due to stock replacement, energy prices and other factors that are projected to occur in the absence of new and incremental market interventions.

Net Metering A system that allows customers with their own small on-site generation facilities (such as solar panels) to "bank" electricity that they generate in excess of their needs and consume electricity from the grid when they need it.

Net Present Value (NPV) The difference between the present value of benefits and the present value of costs (including capital, operating, maintenance and administration costs) for a given discount rate.

Peak Capacity The maximum amount of electrical power that generating stations can produce in any instant.

Peak Demand/Load The maximum instantaneous demand on a power system. Normally, the maximum hourly demand.

Persistence The timeframe during which demand-side measures produce electricity savings that are attributable to the utility’s actions.

Photovoltaic (PV) Direct conversion of light into electricity by semi-conductor diodes called photovoltaic cells, especially using sunlight.

Portfolio A group of individual resource options to be acquired in a sequence over time to fill customers’ future electricity needs.

Portfolio Analysis A process of developing and evaluating resource portfolios, each consisting of a combination of supply side and demand-side resources, which meet customers’ electricity needs.

Present Value (PV) Today’s discounted value of future receipts or expenditures.

Price elasticity of demand The percentage change in quantity demanded, divided by the percentage change in price that caused the change in quantity demanded.

Pumped Storage (PS) The use of electricity generated during off-peak hours to pump water from a lower elevation reservoir to a higher reservoir. The stored water is then released during peak demand periods and used to propel a reversible pump/turbine generator before returning to the lower reservoir.
Reassessing the Need for Site C

Rate Term used for a utility’s unit price of service.

Reliability A measure of the adequacy and security of electric service. Adequacy refers to the existence of sufficient facilities in the system to satisfy the load demand and system operational constraints. Security refers to the system’s ability to respond to transient disturbances in the system.

Resource Option A source of electricity that is available to help meet or reduce electricity demand, including generation, purchases, demand-side measures and transmission facilities.

Revenue Requirements Application (RRA) Application before the B.C. Utilities Commission expected to determine the revenues BC Hydro will need for its operations, to ensure a safe and reliable supply of electricity to its customers.

Run-of-River A hydroelectric facility that operates with no significant storage facilities.

Self-Generation Generation of electricity by an industry or commercial enterprise whose principal product is not electricity. Self-generation can reduce the amount of electricity purchased from the utility, or surplus electricity may be sold to the utility as a supply side resource.

Simple-Cycle Gas Turbine (SCGT) A stand-alone generating plant that uses combustion gases to propel a turbine similar to a jet engine connected to an electrical generator.

Site C Project An 1100 MW, hydroelectric generating station under construction downstream from the existing Williston Reservoir and two existing generating facilities on the Peace River region.

System Optimizer A deterministic optimization model used by BC Hydro that produces an optimal sequence of generation and transmission resource expansions for a predefined scenario by selecting from the stack of available resources.

Total Resource Cost (TRC) Test A DSM benefit-cost test that indicates the impact of a DSM initiative or portfolio from the perspective of all utility customers (also referred to as the All Ratepayers Test). The benefit-cost ratio is calculated as follows:

\[
PV \left( \frac{\text{avoided electric energy costs} + \text{avoided electric capacity costs} + \text{avoided non-electric fuel costs} + \text{customer non-energy benefits}}{\text{PV} \left( \text{BC Hydro program costs} + \text{BC Hydro allocated supporting initiative costs} + \text{customer costs} + \text{partner organization program costs} \right)} \right)
\]

Transmission The transportation or conveyance of electricity in bulk, usually at voltages over 69 kV.
Reassessing the Need for Site C

**Unit Capacity Cost (UEC)** Present value of the total annual cost of a capacity resource divided by the resource’s dependable capacity. It is measured in dollars per kilowatt per year.

**Unit Energy Cost (UCC)** Present value of the total annual cost of an energy resource divided by the present value of its annual average energy benefit. It is calculated using either a discounted cash flow method or annualized cost method, and is measured in dollars per MWh.

**Utility Cost Test** A DSM benefit-cost test that indicates the impact of a DSM initiative or portfolio from the utility’s perspective. The benefit-cost ratio is calculated as follows:

\[
\frac{\text{PV (Avoided electric energy costs + avoided electric capacity costs)}}{\text{PV (BC Hydro program costs + BC Hydro incentive costs + BC Hydro allocated supporting initiative costs)}}
\]

**Wheeling** The transmission of electric power from one system to another through a third party, usually the owner or operator of the transmission facilities.

**Wind Integration Costs** Costs that will be incurred by a utility in managing and operating its system to regulate the intermittent variability of generation from wind resources.
Need for, Purpose of and Alternatives to the Site C Hydroelectric Project

ABRIDGED VERSION

prepared for the
Joint Review Panel
for the Site C Clean Energy Project

on behalf of
the Treaty 8 First Nations

by

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1. ENERGY PLANNING CONTEXT

In many ways, the Site C environmental assessment proceeding is the fruit of various provisions of British Columbia’s Clean Energy Act (the “CEA”). The CEA includes Site C as a “heritage asset” (in Schedule 1) even though it has not been built, and exempts it from normal regulatory scrutiny by the BCUC. It imposes several planning constraints on BC Hydro that seem to presuppose that Site C will be developed.\(^1\) Furthermore, it also exempts BC Hydro’s Integrated Resource Plan (IRP), which recommends building Site C for the earliest in-service date of 2024, from the BCUC’s jurisdiction.

However, the process that led to the CEA did not include a careful weighing of the economic, environmental, social and aboriginal rights implications of developing Site C, as compared to other ways of meeting British Columbia’s energy and capacity needs. It is therefore essential that the Joint Review Panel (JRP) and the governments to which it reports examine critically the pros and cons of proceeding with the Site C Project.

The information submitted by BC Hydro to the Joint Review Panel (JRP) with respect to “need for, purpose of and alternatives to” the Site C Project is, for all intents and purposes, drawn from its Integrated Resource Plan (IRP). To get a sense of scale, the justification-related sections of the EIS total less than 100 pages, whereas the IRP is more than 500 pages, plus over 1000 pages of appendices. Explicitly or implicitly, the source of all information presented in the justification section of the Environmental Impact Statement (EIS) is found in the IRP.

This unusual situation poses an important challenge. It is impossible to critically assess BC Hydro’s case for the need for, purpose of and alternatives to the Site C project, based on a mere

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\(^1\) These include a “self-sufficiency” requirement that blocks imports, a 93% minimum requirement for “clean or renewable energy”, and the forced closure of the Burrard Thermal plant.
summary. To get to the heart of the matter, one must address the original documents, which are found, to the extent that they have been made public, in the IRP and its appendices.

2. NEED FOR, PURPOSE OF AND ALTERNATIVES TO THE PROPOSED PROJECT

2.1. Need for the Project

In the EIS, the Proponent states that: “The need for the Project is to address future customer demand … for firm energy and dependable capacity…”

The Proponent does not claim a need for the 5,100 GWh/yr of energy or for the 1,100 MW of capacity starting in 2024 that the proposed Site C Project would provide. Rather, the need is stated in general terms: the Proponent has a need for resources that would allow it to meet future customer demand.

In fact, the 2013 IRP makes clear that it is the need for capacity that drives its planning process. The problem that the Site C Project is intended to solve is thus BC Hydro’s need for additional capacity.

2.2. Purpose of the Project

In the EIS, BC Hydro states:

The purpose of the Project is to:

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2 Section 5.2.

3 The term “capacity” refers to a utility’s ability to meet peak demand. For example, a hydro utility may have enough water stored in its reservoirs to meet annual energy needs (energy adequacy), but still be unable to meet peak demand on the coldest or warmest day of the year (capacity shortfall). Energy requirements are measured in gigawatthours (1 GWh = 1,000,000 kWh); peak capacity requirements are measured in megawatts (1 MW = 1,000,000 watts).
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• Cost-effectively meet BC Hydro’s forecasted need for energy and capacity …

• Align with the relevant objectives of Section 2 of the Clean Energy Act and relevant B.C. Government policy statements, which in turn were used to develop Project-specific objectives, including the objective to maximize the development of the hydroelectric potential of the Site C Flood Reserve. …

The primary purpose of the project is thus to meet the identified need “cost-effectively,” i.e. at lower cost than the alternative means of meeting the need. As noted above, that need is above all a need for capacity.

The EIS also asserts a secondary purpose, which is more problematic: “to maximize the development of the hydroelectric potential of the Site C Flood Reserve.” If this objective is retained, there can be no alternatives possible — only “alternative means to carry out the Project”, since none of the alternatives to meet BC Hydro’s capacity needs would maximize the development of the hydroelectric potential of the Site C Flood Reserve.

The Joint Review Panel’s terms of reference require it to examine “alternatives to the Project” (s. 2.2), as recommended by the Operational Policy Statement. In order to make such an examination possible, the Joint Review Panel should follow the lead of the Panel in the Lower Churchill Panel Review and disregard the claimed objective “to maximize the development of the hydroelectric potential of the Site C Flood Reserve”. Instead, it should conclude that the Purpose of the Project, from the Proponent’s perspective, is to cost-effectively meet BC Hydro’s forecast need for capacity and, to a lesser extent, energy.

2.3. Alternatives to the Project

In the EIS, the Proponent describes the “technically and economically feasible alternatives to the Project” by first identifying Available Resources, after “Screening” potential alternatives that it

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4 EIS, s. 5.3, p.5-22
considers to be “not viable”.

It is important to recognize that the Available Resources do not in themselves constitute Alternatives to the Project. Rather, they are components of larger portfolios that may or may not include the Project. Portfolios without the Project are thus the Alternatives to which the Project (or rather, a portfolio including the Project) is compared.

Thus, it is only through portfolio analysis that one can determine the cost-effectiveness of the Project as compared to the Alternatives. Considerable scrutiny is therefore required of this portfolio analysis and of the choice of resources to be included or excluded.

3. THE PROPOSENT’S ALTERNATIVES ANALYSIS

3.1. Available Resources

BC Hydro begins its analysis by identifying the Available Resources. In doing so, however, it has:

- applied a constraint that artificially limits the use of Simple Cycle Gas Turbines for capacity needs;
- neglected to include DSM Capacity Resources, which are “screened” (excluded) by the Proponent; and
- neglected to include DSM Option 3, a more aggressive version of the existing demand-side management programs.

In the following sections, we shall look at each of these in turn.

3.1.1. Simple Cycle Gas Turbines (SCGT) as a capacity resource

The CEA establishes the objective of generating at least 93% of the electricity in B.C. from clean (i.e. non-greenhouse gas emitting) or renewable resources. The 2013 IRP concludes that the
optimal use of the remaining 7% “GHG headroom” is as a transmission alternative or as a “capacity and contingency resource”.

BC Hydro correctly identifies simple-cycle gas turbines (SCGTs) as a capacity resource. However, it makes an unjustified assumption that substantially limits the usefulness of this resource: that SCGTs will operate with an 18% capacity factor. This implies that, on average, an SCGT will operate $18\% \times 8760 = 1577$ hours per year — the equivalent of operating 8 hours a day for almost 200 days a year.

BC Hydro justifies this position by maintaining that capacity resources should be capable of operating from 6am to 10pm, 6 days a week, from November through February. However, just because a resource is capable of operating for that many hours does not mean that it is likely to do so. In reality, some capacity resources are operated less than 1% of the time, others around 5%, and so on.

Assuming such a high capacity factor means that each SCGT uses up a significant portion of the 7% “GHG headroom” under the Clean Energy Act. Because so much natural gas is assumed to be used each time an SCGT is built for capacity purposes, this flexible and inexpensive capacity resource is used only sparingly in the Proponent’s scenarios.

The alternate resource scenarios presented below do not retain this assumption, allowing SCGT’s to operate as little as 5% of the time. As a result, they become a much more flexible and cost-effective capacity resource — far less expensive than developing Site C to meet capacity needs, as we shall see below.
3.1.2. DSM Options

In the EIS, the Proponent describes its current DSM Target and describes the DSM Options that it developed. To understand the full range of the five DSM Options considered by BC Hydro, however, one must look to the 2012 Draft IRP.

Each of the five Options is a package of measures and programs, of increasing intensity, consisting of five components: codes and standards, conservation rate structures, programs, supporting initiatives and other tactics. Each DSM Option pursues these five components more aggressively than the Option before it.

The current DSM path is Option 2. In the EIS, Options 4 and 5 were identified as Screened Resources, because, in the Proponent’s view, they present “government and customer acceptance issues” and delivery risk.

In the EIS, DSM Option 3 was neither screened nor included as an Available Resource. In response to criticism, this omission was corrected in the Evidentiary Update,\(^7\) which identified DSM Option 3 as an Available Resource. The Update then presented, in summary fashion, the results of a portfolio comparison purporting to demonstrate that DSM Option 3 would result in increasing present value costs. However, no details are provided as to the comparison made or the assumptions used.

In the 2013 IRP, however, we learn the real reason for excluding DSM Option 3: that it is incompatible with the need to scale back DSM in the short-term to respond to the current energy surplus and the financial difficulties facing BC Hydro.

For DSM Option 3, the ability to reduce current expenditure levels was considered but dismissed. Option 3 targeted increased program activities and expenditures to target the greatest level of DSM program savings currently considered deliverable. It is BC Hydro’s professional judgement that to reduce near-term expenditures but continue to rely upon the

\(^7\) BC Hydro, Evidentiary Update, Sept. 13, 2013, p. 4.
longer term savings is not believable or prudent in the case of DSM Option 3. (underlining added)

In other words, BC Hydro chose Option 2 for the long term because, given its planned cutbacks in DSM spending in the short-term, Option 3 was no longer viable.

Handicapping future DSM to palliate a surplus resulting from past planning errors is a short-sighted strategy, and incompatible with the importance given to DSM in the statutory Energy Objectives in the *CEA*. Forcing DSM to act as the marginal resource to be scaled down whenever supply-side resources are over-acquired will continue to prevent DSM from taking its preferred place in the resource portfolio. In fact, the short-term savings from cutting back DSM are small compared to the long-term costs that flow from this short-sighted decision.

By the mid-2020s, choosing DSM Option 3 over DSM Option 2 would result in additional savings of over 200 MW of capacity and over 1,200 GWh/yr of energy. These savings are substantial and are used in the alternate portfolios described below in section 4.

### 3.1.3. DSM Capacity Initiatives

Traditional DSM programs are focussed primarily on saving energy, though they do also reduce capacity needs. DSM Capacity Initiatives (also referred to as “Capacity-focused DSM”) refer to measures that are specifically designed to reduce peak demand. These initiatives were considered by BC Hydro not to be Available Resources, because they were found to be “not viable”.

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8 Final IRP, s. 4.2.5.2, “Delay Planned Ramp-ups in Spending on DSM Activities,” p. 4-18.

9 For example, a program that provides incentives for home insulation reduces the total amount of energy a house requires per year (energy requirements), but it also reduces the amount of power required during the coldest day of the year (capacity requirements).
In defence of this position, BC Hydro argues that these resources are not yet well understood, and that pilot projects will be required. These are legitimate concerns. As with energy-focused DSM, there is a learning curve, and BC Hydro is less advanced with respect to capacity-focused DSM.

It would be entirely reasonable, considering these factors, to discount to a certain extent the amount of capacity-focused DSM that will actually be achieved. However, to screen this potential entirely, thereby assuming that **0 MW** of capacity-focused DSM will be achieved **in the next 20 years** cannot be justified.

Not only does BC Hydro inappropriately exclude all DSM capacity initiatives, it has also chosen to completely ignore the capacity-saving potential of time-of-use rates, which it had recognized in its 2012 Draft IRP.

The capacity-focused DSM initiatives identified in the EIS consist of just two resources: Industrial load curtailment and “capacity programs”, having mean expected capacity savings of 382 MW and 193 MW, respectively.

Time of use (TOU) rates were identified as a capacity resource in the 2012 Draft IRP. A time-of-use rate structure, which imposes more expensive rates during peak periods, tends to shift consumption from peak to off-peak, thereby reducing peak demand. Capacity savings of over 400 MW were attributed to this option in 2012, bringing the combined capacity savings for capacity-focused DSM to over 1,000 MW, as shown in Figure 1.

**None of these capacity resources are called upon in BC Hydro’s Integrated Resource Plan.**
During the debates about Smart Meters, the former energy Minister apparently spoke out against time-of-use rates. However, in 2011, BC Hydro project manager Gary Murphy was quoted as saying:

> If the choice that customers have in the future is between building more generating capacity or going to time-of-use rates, economically it’s a clear slam-dunk. It’s cheaper to conserve than to build new generators.\(^1\)

The current energy minister has in fact shown interest in time-of-use rates, asking the BC Industrial Electricity Policy Review Task Force to study them. This Task Force has recently recommended that BC Hydro offer options such as retail access and time-of-use rates to reduce costs and electricity demand for industrial customers, and the government has indicated it will act on this recommendation. There is thus no reason to exclude time-of-use rates from the potential capacity-focused DSM.

\(^{10}\) “No time-of-use billing for B.C., Energy Minister insists,” The Globe and Mail, Tuesday, Sep. 27, 2011.
More broadly, there is no reason to exclude capacity-focused DSM from the Proponent’s list of Available Resources. By all measures, capacity-focused DSM is an extremely important and cost-effective component for alternate portfolios to be compared to those built around Site C.

Given the size of this resource (similar to that of Site C) and its very low cost, the Proponent’s decision to exclude capacity-focused DSM entirely from consideration vitiates and invalidates the alternatives analysis on which the EIS rests.

### 3.2. Block vs. Portfolio Analysis

The IRP makes clear that BC Hydro carries out two distinct types of resource analysis: block analysis and portfolio analysis. While the EIS also mentions these two types of analysis, the results presented therein are in fact those of the block analysis. The portfolio analysis, which represents the heart of BC Hydro’s planning process, is essentially ignored in the EIS.

#### 3.2.1. Block analysis

The Block Analysis compares Site C to similarly sized blocks of energy and capacity from other sources. This approach is fundamentally flawed. The commissioning of Site C would be accompanied by enormous capacity and energy surpluses, especially in low-load scenarios, and, as we shall see below, the revenues that would result from exporting those surpluses are far less than the annual cost of Site C. Thus, the “lumpiness” of Site C is a significant disadvantage in relation to more modular resources. Indeed, grasping the scope and depth of these surpluses, and their financial consequences, is one of the key challenges to assessing the characteristics of Site C, from an energy planning perspective. Therefore, comparing Site C to “blocks” of other resources that artificially reproduce the same surpluses is an exercise of little value. Yet it is on this type of analysis that the conclusions presented in the EIS are for the most part based.

The Block Analysis in the EIS refers to three categories of portfolios:
- Portfolios including Site C,
- Portfolios excluding Site C, which do not include thermal generation (Clean Generation Portfolios), and
- Clean + Thermal Generation Portfolios, which use SCGTs to provide capacity.

All three portfolios were designed to provide the same amounts of energy and capacity as Site C (1100 MW and 5,100 GWh/yr). Figure 5.11 from the EIS, which compares the capacity of the three block portfolios, is reproduced below as Figure 2.

In other words, the Block Analysis presented in the EIS compares three generation portfolios, one of which unavoidably creates an expensive surplus (Site C), and the other two which expressly and unnecessarily recreate the same expensive surplus. This analysis is without probative value.
3.2.2. Portfolio analysis (System Optimizer)

The portfolio analysis eliminates this problem by building optimized portfolios for each set of assumptions. A portfolio analysis of this type was explicitly presented in the IRP, but not in the EIS.

In the IRP, two types of analysis are clearly distinguished:

1. The block comparison compares Site C to its alternatives over their project lives and demonstrates the long term value of Site C.

2. The second method creates and evaluates portfolios using the linear optimization model (System Optimizer) that selects the optimal combinations of resources over a 30-year planning horizon under different assumptions and constraints. The analysis using System Optimizer is a more sophisticated approach and provides additional information not captured by the simple unit cost comparison …

The energy planning exercise that underpins the IRP is the second method. It examined more than 50 scenarios, each one defined by the load growth scenario, the LNG scenario, the DSM Option, DSM deliverability, the market price scenario, the inclusion or not of Site C, and other parameters. For each scenario, System Optimizer selects the resource portfolio that minimizes total present value costs. Thus, unlike in the Block Analysis, the alternative portfolios are not forced to reproduce the Site C surplus. However, this portfolio analysis is nevertheless tainted by its failure to consider the resources discussed above (low capacity-factor SCGTs, DSM Option 3, and DSM Capacity Initiatives).

Based on BC Hydro’s portfolio analysis, the IRP develops Base Resource Plans (BRPs) and Contingency Resource Plans (CRPs), both with and without LNG. The CRP with LNG is a

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11 While a large number of scenarios are analyzed, the vast majority of them use the mid-load forecast and DSM Option 2, with medium DSM deliverability. Only four scenarios use the low load forecast (with and without Site C, and with and without thermal resources); there is no exploration of the effect of low market prices or high DSM deliverability, for example, in a low load scenario. Similarly, only three scenarios use DSM Option 3. No scenarios use Capacity-focused DSM, and none use higher-than-average deliverability from DSM.
“worst-case” scenario from a reliability standpoint, with high load growth, low DSM deliverability, and new loads due to LNG development.\textsuperscript{12}

In Section 4, I will reconstruct these Resource Plans, taking into account the additional resources described above.

### 3.3. The Size and Cost of the Site C Surplus

As we have seen, in the EIS BC Hydro calculates the benefits to the ratepayer of the Site C Project, by comparing its cost to the “avoided cost” of similarly sized blocks of energy and capacity. The results appear to present unequivocal proof the Site C Project is more cost-effective than the alternatives.

However, \textbf{these results are based on the Block Analysis described above}. The Clean and Clean + Thermal portfolios are forced to reproduce the large and expensive surplus that Site C would create. The benefit flowing from the flexibility inherent in these approaches is simply lost.

A significant portion of the Site C Project’s energy and capacity will be surplus to BC Hydro’s needs for many years after the in-service date, and is subject to many uncertainties. Surplus energy has little economic value considering current and expected export market prices, and surplus capacity has little or no economic value.\textsuperscript{13}

\textsuperscript{12} The new LNG loads do not include the energy required for compression, which it is assumed will be provided by natural gas.

\textsuperscript{13} BC Hydro has recently argued that its surplus capacity may in fact have some value in the California market. Even if this is turns out to be the case, it is unlikely that the value would be significant, in relation to the annual cost of the Site C Project.
There is no way to develop the Site C project without creating these large surpluses. However, that is not true for the resources that make up the other two Block Portfolios (Clean and Clean+Thermal). A present value cost comparison between these three Block Portfolios is thus entirely misleading.

To better understand the scope of the energy surpluses in the Site C portfolios, it is necessary to look at the scenarios presented in Appendix 6A of the 2013 IRP. For each one, a graph is presented which shows year-by-year imports and exports under the scenario modelled. The blue line in these figures shows the net exports (on- and off-peak exports minus off-peak imports) for each year from 2016 through 2040.

Figure 3 shows imports and exports for the first portfolio presented by BC Hydro as the “Site C Base Case.” It shows net exports (the blue line) of about 6 TWh in 2016. They fall to 1 TWh in 2022, and then rise gain to 6 TWh in 2024, with commissioning of Site C. Net exports remain positive through 2033.

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14 BC Hydro, Draft IRP, August 2013, Appendix 6A, Scenario M&M_1LC_NN0_05Q, p. 6A-40.
In order to get an idea of the magnitude of these effects, it is useful to evaluate the cost of the Site C project from a capacity perspective. Given that the underlying need for the Site C project is to meet the Proponent’s capacity requirements, one could also describe the costs of Site C as a capacity resource.

In the years when much of the energy from Site C is surplus to BC needs and so will have to be exported (at a loss), the Project’s capacity cost is very high. BC Hydro has acknowledged that, under the medium market price scenario, Site C’s capacity cost will be over $300/kW-yr in the initial years after commissioning, when its energy is 100% surplus. As seen in Figure 4, if all of
the energy from Site C were to be exported, its capacity unit cost would remain over $225/kW-yr throughout the planning period, again under the medium market price scenario.\footnote{BC Hydro acknowledges this in its Rebuttal Testimony, p. 12, Figure 1.}

\begin{table}[h]
\begin{tabular}{|l|c|l|}
\hline
 & Capacity Cost & Source \\
 & ($/kW-yr) & \\
\hline
SCGT & $100 & Evidentiary Update, p. 60 \\
Revelstoke Unit 6 & $50 & Evidentiary Update, p. 60 \\
GSM Units 1-5 & $35 & Evidentiary Update, p. 60 \\
Industrial load curtailment & $45 & 2013 IRP, Table 3-6, p. 3-30 \\
Capacity-Focused Programs & $69 & 2013 IRP, Table 3-6, p. 3-30 \\
TOU Rates & Very low & 2012 IRP, Figure 3-5, p. 3-21 \\
\hline
\end{tabular}
\end{table}
In later years, the effective capital cost of Site C depends on the value we attribute to the energy used in BC. If Site C energy used by BC Hydro customers is valued at the price at which it could be purchased in the (import) market, the capacity cost remains at high levels. If, on the other hand, it is assumed that the alternative energy supply consists of expensive new renewables, this effect tapers off sharply. In either case, though, throughout the 2020s, Site C remains a very expensive capacity resource.

The picture is much worse under the low load growth scenario. The following chart shows the low load scenario, with Site C in service in 2024.

*Figure 5. Scenario L&L_1LC_NN0_05Q (low load growth, DSM Option 2 with low deliverability, no LNG, Site C)*

In this scenario, there is already a large surplus at the beginning of the period, with net exports of about 9500 GWh in 2017. With Site C, net exports rise to almost 10,000 GWh in 2024, and decline only gradually. By 2040, they are still almost 3000 GWh, or more than half of the energy output of Site C. This would imply a capacity cost for Site C of more than $150/kW-year, through 2040.
Without Site C, net exports would decrease much more rapidly, and reach zero around 2035. BC Hydro acknowledges that the present value costs for this scenario are more than $1 billion dollars less than for the scenario with Site C.\footnote{BC Hydro, 2013 Final IRP, Appendix 6A, Table 4, p. 6A-37 (small gap portfolios).}

Given that the constant-dollar unit costs of Site C (about $94/MWh) are considerably greater than the forecast export prices ($28 to $44/MWh, according to the medium forecast\footnote{For the years 2024 through 2040. BC Hydro, 2013 Final IRP, Appendix 5A, p. 5A-7.}), the fact that a substantial portion of the energy generated by Site C will be sold at export for a number of years will inevitably have an adverse effect on the project’s profitability. However, the Proponent’s methodology of using a Block Analysis to compare Site C to portfolios of the same size (capacity and energy) has the result of making this effect disappear. It thus cannot be relied on for decision-making purposes.

4. ALTERNATIVES TO THE PROPOSED PROJECT

As noted above, the Alternatives to the Project consist of portfolios that meet BC’s energy and capacity needs but that do not include the Project.

We have seen in the previous section that the Proponent’s analysis of alternatives is fundamentally flawed because it is based on a Block Analysis that only compares the proposed Site C project to alternate portfolios that intentionally and unnecessarily share the proposed Project’s greatest flaw — its large scale, and the surpluses that result therefrom.

We have also seen that the Proponent’s analysis ignored several alternate resources that should have been considered, including DSM Option 3, DSM capacity-focused resources and SCGTs as a pure capacity resource.
In this section, I will present an alternatives analysis that remedies both these flaws. Using different load scenarios, this analysis compares the detailed resource plans prepared by BC Hydro to alternate plans that take advantage of the additional resources described above in section 3.1.

As we shall see, all of the alternative portfolios analyzed have lower present value costs than the corresponding portfolios containing Site C. This demonstrates the importance of the resource options that were excluded from the IRP and the EIS.

While the exercise described here is quantitative, its significance is qualitative. It demonstrates that the exclusion of key Available Resources, such as DSM Option 3, DSM Capacity Initiatives, and low capacity factor SCGTs, really does affect the outcome significantly. It shows that, once corrected in this way, the portfolios containing Site C are consistently more costly than the alternatives.

The Recommended Actions in BC Hydro’s 2013 IRP are based on four Resource Plans: Base Resource Plans (BRPs) with and without LNG, and Contingency Resource Plans (CRPs), again with and without LNG. These plans were all developed using the scenario portfolio analysis described earlier. The BRPs are based on the medium load growth scenario, with medium deliverability of DSM; the CRPs are based on the high load growth scenario and low deliverability of DSM.

For the sake of simplicity, I will focus on the lowest and highest of the four scenarios: BRP without LNG, and CRP with LNG. At the same time, I will look at outcomes under an additional scenario that BC Hydro did not include in its Resource Plans, in which load growth follows the low scenario (the “Low Growth Resource Plan”, or LGRP).

For each of these scenarios, I have prepared an alternate resource plan that does not include Site C.
All of these alternate resource plans make use of the resources discussed above which were
unnecessarily excluded from the Proponent’s analysis, namely DSM Option 3, capacity-focused
DSM and low capacity-factor SCGTs.

These portfolios all respect the constraints created by the *Clean Energy Act*:

- The self-sufficiency requirement, which dictates that in-province generation be
  sufficient to meet the mid-load forecast;\(^{18}\)
- The requirement that 93% of all BC generation be from “Clean” or renewable
  sources.

In each of these alternate portfolios, capacity savings for Industrial Load Curtailment and
Capacity-focused DSM programs have been maintained at the P10 level described in the EIS.\(^{19}\)
Time of Use capacity savings have been reduced to 50% of the potential indicated in the 2012
Draft IRP. To respond to BC Hydro’s concerns about relying exclusively on demand-side
resources for capacity needs, an additional 200 MW or more of SCGTs or other supply-side
capacity resources have been added starting in 2020, resulting in a substantial planned capacity
surplus throughout the 2020s.

I have also proposed “optimized” Site C portfolios, which also use these demand-side resource
alternatives in addition to Site C, when doing so results in cost reductions.

For each alternate portfolio, I have calculated the year-by-year costs for *resources which are
removed from or added to the underlying BRP or CRP scenario*.\(^{20}\) The costs are based on
levelized unit energy costs provided by BC Hydro, as well as year-by-year import costs and

\(^{18}\) This does not apply to the CRP, which is based on high load forecast.

\(^{19}\) The P10 level is the level that BC Hydro estimates will be exceeded 90% of the time. It is thus a very
  conservative estimate of future capacity savings.

\(^{20}\) These include capacity costs (annual cost of new equipment required to meet capacity requirements),
  energy costs (market purchases and energy costs of clean and gas-fired resources, net of export
  revenues), and additional DSM costs.
export revenues, based on BC Hydro’s long-term medium market price forecast (found in Appendix 5A of the 2013 IRP). The present value is then calculated for these year-to-year costs and revenues, for each scenario.

This differential cost analysis only reflects the elements that change from one scenario to another. Costs of elements that remain unchanged are not included in this analysis. Thus, the costs reported here are only meaningful in comparison one to the other, and are not comparable to the total portfolio costs presented in the EIS or the IRP.

4.1. Base Resource Plan without LNG

The Base Resource Plan (BRP) represents BC Hydro’s base-case scenario, based on the medium load growth scenario and medium DSM deliverability.

4.1.1. BC Hydro’s Base Resource Plan without LNG, with Site C

BC Hydro’s Base Resource Plan (BRP) without LNG is portrayed graphically in the IRP as follows:
In this scenario, all of the energy and most of the capacity of Site C are surplus to BC Hydro’s needs (the dashed green line, which represents demand after conservation) upon commissioning.

4.1.2. BRP without LNG, with Site C (optimized)

Capacity-focused DSM programs and DSM Option 3 make it possible to defer the capacity need for Site C until 2029. GMS Units 1-5 Capacity Increase is added as of F2021, to provide “insurance” for the reliance on DSM for capacity needs. This results in savings of $260 million in relation to the original BRP. By deferring the commissioning date of Site C, this scenario also creates an unquantified flexibility benefit, in delaying the go/no-go date to a point where many of the uncertainties regarding demand-side resources and LNG development will likely be resolved.
4.1.3. BRP without LNG, without Site C

As in the previous portfolio, GMS Units 1-5 Capacity Increase is added early to provide capacity insurance, and CCGTs are added, within the limits of gas headroom, to meet energy needs. Additional energy needs are met with Clean Resources. In F2029, 125 MW of CCGTs are added,
increasing to 145 MW in F2033.\textsuperscript{21} Revelstoke Unit 6 is added in F2031; Clean Resources are also added starting with 400 GWh in F2030, increasing to 2,500 GWh in F2033.

Capacity and energy balances for this portfolio are presented in Appendix 1.

As we shall see in the next section, the present value costs of this portfolio are $610 million less than under the IRP, and $350 million less than under the comparable optimized Site C portfolio.

\textsuperscript{21} In practice, this would probably mean building a 150 MW CCGT in F2029 and operating it at the average levels indicated here.
4.1.4. Differential cost comparison

The red line in the next graph represents the annual costs of the elements mentioned earlier\(^{22}\) for BC Hydro’s BRP without LNG. The dashed red line represents the annual differential costs of my optimized Site C portfolio. The dotted green line represents the annual differential costs of a portfolio without Site C.

\(^{22}\) The costs of resources removed from or added to the underlying BRP or CRP scenario. See note 20.
Again, it is important to recall that these curves represent only the cost categories that vary among the different plans. Thus, only their relative values are meaningful.

In the years 2014-2023, the alternative portfolios are more expensive than the IRP (Site C) portfolio (the solid red line), primarily because of the additional DSM costs (Option 3 and the new capacity-focused DSM programs). In the Site C (optimized) case (the dashed red line), the spike representing commissioning of Site C is deferred by six years (due to the additional DSM), and is also smaller, since the energy surplus is smaller as well. In both cases, the surpluses resulting from the commissioning of Site C, which are exported at a price far below cost, result in higher differential costs than the “without Site C” case, despite the higher unit costs of the Clean Resources. This effect is limited because the natural gas headroom makes it possible to meet some of the energy shortfall with CCGTs.
The present value of each of these three cost series, using BC Hydro’s 5% real discount rate, is shown in the following chart.

Again, it is the relationship between the differential PV costs of each portfolio that is meaningful, not the absolute value. Thus, this exercise demonstrates that, in the BRP scenario without LNG, optimizing Site C by delaying its commissioning through the use of additional DSM and other options discussed above would reduce present value portfolio costs by $260 million. Eliminating Site C by adding low capacity factor SCGTs to meet peak capacity needs would lower PV costs by an additional $350 million, for a total savings of $610 million compared to BC Hydro’s BRP.

### 4.2. Contingency Resource Plan with LNG

The Contingency Resource Plan is meant to ensure that BC Hydro will be able to meet its demand even under the most challenging conditions. This is thus BC Hydro’s most demanding scenario, based on high load growth, low DSM deliverability and LNG loads.
4.2.1. BC Hydro’s Contingency Resource Plan with LNG, with Site C

The capacity chart for the CRP (with LNG) presented in the 2013 IRP is as follows:

**Figure 12. CRP with LNG (Site C, IRP) - Energy**

![Energy Chart](image1)

**Figure 13. CRP with LNG (Site C, IRP) - Capacity**

![Capacity Chart](image2)
Under this BC Hydro portfolio, 400 MW of gas-fired generation are added in 2020, 294 MW in 2021, 196 MW in 2022, and another 1,078 MW between 2029 and 2032, for a total of 1,960 MW of simple cycle gas-fired generation (SCGT).

In both CRPs (with and without LNG) there are substantial market energy purchases later in this decade, reaching 4.5 TWh in 2019.

As before, I have prepared two alternate resource plans based on BC Hydro’s Contingency Resource Plan with LNG.

4.2.2. CRP with LNG — Site C (optimized)

As we saw earlier in the BRP, the economics of the Site C option can be improved by deferring the In-Service Date, combined with the capacity-focused DSM programs discussed earlier and a combination of combined-cycle and simple-cycle gas turbines.

It is interesting to note that, in the CRP scenario published in the 2013 IRP, gas-generated electricity exceeds the 7% CEA Objective from F2031 on. In this optimized Site C portfolio, gas generation never exceeds the 7% limit. It adds 125 to 225 MW of CCGTs, as well as 200 MW of SCGTs, increasing to 450 MW in F2026 and growing to 1,000 MW in the last three years of the planning period.

I have also used market energy purchases to limit the amount of more expensive Clean Resources required. In the detailed CRP (with LNG) published in the IRP, market purchases rise to 4,506 GWh in F2019, but then taper off. As the self-sufficiency section of the CEA only

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23 In F2033, App. 9A of the Final IRP shows 3,000 GWh of electricity from the 1,960 MW of SCGTs. Added to the existing gas generation of 3,520 GWh, yields 6,520 GWh out of a total supply of 84,290 GWh, or 7.7%.
applies to planning under mid-level forecasts,\(^\text{24}\) there appears to be no legal obstacle to continuing to use low-cost electricity imports in the CRP. In this and the following portfolios, energy purchases up to, but not exceeding, the level used in BC Hydro’s CRP portfolios have been allowed.

Even in this high load contingency scenario, the combination of capacity-focused DSM, gas turbines, energy purchases and clean resources makes it possible to defer Site C until 2027. The result is to avoid creating an energy surplus and to reduce differential costs by $435 million, compared to BC Hydro’s CRP.

\(^{24}\) S. 6(2) requires BC Hydro to hold “rights to an amount of electricity that meets the electricity supply obligations solely from electricity generating facilities within the Province”. “Electricity supply obligations” is defined in s. 6(1) to be determined “by using the authority's prescribed forecasts”. “Prescribed forecasts” is defined in s. 2 of the Electricity Self-Sufficiency Regulation as “the authority’s mid-level forecasts”. 
4.2.3. CRP with LNG — without Site C

As in the previous scenario, CCGTs, Clean Resources and purchases provide virtually all the additional energy requirements. Additional capacity is provided by Revelstoke 6, GMS Units 1-5 and SCGTs. The full 7% gas headroom is utilized for much of the planning period, but is never exceeded.

Capacity and energy balances for this portfolio are presented in Appendix 2.
Differential costs are $743 million less than in the original CRP, and are $309 million less than the optimized CRP with Site C. Once again, the primary reasons are the substitution of energy from Site C with energy from combined cycle gas turbines and from purchases, both at a significantly lower cost.
4.2.4. Differential cost comparison

As shown in the following graph, the differential present value costs for the Site C portfolio, even when optimized, exceed those without Site C.\textsuperscript{25}

![Figure 16](image)

These amended portfolios therefore confirm the “astounding result that even when there is significant need the portfolios containing the Project are the high cost option.”\textsuperscript{26}

\textsuperscript{25} The differential present value costs are considerably higher than in my original Submission because they now include the full cost of all the Clean Resources (the pale green bars in the energy and capacity charts). The cost of Clean Resources was not a differential cost in the original Submission, because it did not vary from one scenario to another.

\textsuperscript{26} BC Hydro Rebuttal Evidence, p. 27, line 9.
4.3. Low Growth Resource Plan (LGRP)

Like most other utilities, in order to quantify the uncertainty in future load growth, BC Hydro prepares a low and high load growth scenario as part of its annual load forecasting exercise. BC Hydro’s Base Resource Plan is based on the medium load growth scenario, and its Contingency Resource Plan is based on the high load growth scenario.

BC Hydro does not present a resource plan that follows its low load scenario. However, its portfolio analysis does include a few runs based on the low scenario, and, using these data, it is possible to generate graphs similar to those presented in the IRP.

4.3.1. Low Growth Resource Plan (LGRP) without LNG – with Site C

Figures 17 and 18 show the energy and capacity balances for under the low load growth scenario, assuming that Site C is commissioned in F2024.

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**Figure 17**

LGRP (with Site C) - Energy

[Graph showing energy balances for different years]

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27 Such as the one shown in Figure 5 on page 17.
The upper chart shows that, under this scenario, the energy surplus in 2032 would be more than 10 TWh — almost double the average annual energy production of Site C!

As seen in the lower chart, under the low load growth scenario, the capacity of Site C would remain entirely surplus to peak demand needs after conservation until 2032.

4.3.2. LGRP without LNG – without Site C

Given that, under the low load scenario, existing resources will exceed demand in 2032, I did not analyze an optimized portfolio including Site C.

The LGRP portfolio without Site C is shown in Figure 18.
Even with no new generation resources, BC Hydro would still have surplus energy and capacity under this scenario, thanks to the increased contribution of DSM. Depending on the relationship between market prices and the marginal cost of these “negawatt-hours”, it may or may not be cost-effective to maintain this level of DSM effort in the later years.
4.3.3. Differential cost comparison

Not surprisingly, the portfolio without Site C displays dramatically lower costs (despite the unnecessarily high levels of DSM), given that Site C would only add to the existing surplus of both energy and capacity.

In the “without Site C” case, export revenues are lower, but eliminating the costs of Site C results in a present value difference of over $1.1 billion, in favour of the “without Site C” portfolio. This finding confirms the similar results of BC Hydro’s portfolio analysis, mentioned on page 18, above.

The differential costs are negative because, in both scenarios, the export revenues exceed the other differential costs. However, because the costs are so much greater in the Site C scenario, the present value costs for the scenario without Site C are over $1 billion less.
5. CONCLUSIONS

In essence, BC Hydro argues that:

1. British Columbia has a need for new energy and capacity resources within the next 10 to 15 years;

2. BC Hydro must be ready to respond to certain eventualities, such as high load growth, low DSM delivery and additional LNG demand; and

3. BC Hydro’s Portfolio Analysis demonstrates that the Project is the most cost-effective way to meet this need.

Regarding the first point, in some scenarios, BC will need new capacity and energy resources in the next 10 to 15 years, though the amounts that will be required depend on many factors, including load growth and the extent of investment in, and the performance of, DSM. **BC Hydro most certainly has not demonstrated that the Site C Project is well matched to the amounts of energy and capacity that will be required.**

As we have seen above, BC Hydro has acknowledged that it is the capacity needs that drive its plan to commission Site C in F2024.

As for the second point, BC Hydro’s contingency resource plans, which rely primarily on gas-fired generation, are meant to respond to these eventualities. (The BRP with LNG also relies on natural gas to meet the additional demand.) Indeed, in the IRP, the “natural gas headroom” allowed under the Clean Energy Act is expressly reserved for these situations. Similar strategies can be applied with and without Site C.

The third point is the most important, as it is the only one that speaks specifically to the Site C Project. BC Hydro writes:
Portfolios including the Project generally have a lower present value of costs to ratepayers, as compared to portfolios including only clean or renewable resources, and portfolios including both clean and thermal resources.\textsuperscript{29}

This is indeed the heart of BC Hydro’s justification analysis. As we have shown above, it is based on the Block Analysis:

The first method is a unit cost comparison whereby the cost of Site C is compared to the cost of similar sized blocks of energy and capacity provided by alternative resources.\textsuperscript{30}

But, as we have shown, the size of the Site C Project is very problematic. Because of the enormous spread between its unit energy costs and the forecast export prices, \textbf{as long as Site C contributes to a surplus that must be exported, it will create a financial deficit that will have to be made up by either ratepayers or taxpayers.}

By limiting its comparison to portfolios of the same size, the Proponent has managed to make this problem seem to disappear. But the problem is still there — it is the analysis that is flawed. This flaw can be remedied by turning to the “more sophisticated” second method described by BC Hydro in its IRP, based on comparing the optimal combinations of resources under different assumptions and constraints.

My analysis explores the consequences, for resource balance and differential costs, of different ways of meeting forecast energy and capacity needs, under different scenarios. Proceeding this way has also made it possible to correct a number of ill-founded choices made by BC Hydro, such as the elimination of DSM Option 3, the total exclusion of DSM Capacity Initiatives, and the assumption that SCGTs must have a minimum capacity factor of 18%.

\textsuperscript{29} BC Hydro, Site C EIS, p.6-121.

\textsuperscript{30} 2013 IRP, pp. 6-30.
The following table summarizes the present value differential costs of the alternate resource plans we have looked at (IRP, Optimized Site C, without Site C), for each of the three scenarios (LGRP without LNG, BRP without LNG, CRP with LNG).

<table>
<thead>
<tr>
<th>Present value differential costs ($ millions)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Site C (IRP)</td>
</tr>
<tr>
<td>Site C (optimized)</td>
</tr>
<tr>
<td>without Site C</td>
</tr>
</tbody>
</table>

It is striking that, for every one of the scenarios reviewed, the portfolio without Site C displays present value differential costs substantially lower than the corresponding Site C portfolios, even when the latter is optimized using the same supply- and demand-side resources as in the alternate portfolios.

Figure 21 shows the additional costs of the optimized Site C portfolio, in relation to portfolios without Site C.
The bar on the left shows that, for a low growth scenario without LNG, the costs for the optimized Site C portfolio are over $1.1 billion more than the portfolio without Site C. For both the BRP without LNG and the CRP with LNG, the optimized Site C present value differential costs are more than $300 million greater than for the corresponding “without Site C” portfolio.

Given these results, one can only conclude that Site C is not a cost-effective solution to meeting BC Hydro’s forecast needs for additional energy and capacity. On the contrary, when compared to alternative portfolios that are not overbuilt to mimic the Site C surpluses, we see that Site C is in fact the most expensive of the alternatives studied.
APPENDIX 1

BASE RESOURCE PLAN (BRP) WITHOUT LNG
CAPACITY AND ENERGY BALANCES

PORTFOLIO WITHOUT SITE C
### Existing and Committed Heritage Resources

<table>
<thead>
<tr>
<th>Year</th>
<th>BRP without LNG (without Site C) - Capacity (MW)</th>
</tr>
</thead>
<tbody>
<tr>
<td>2014</td>
<td>10,152</td>
</tr>
<tr>
<td>2015</td>
<td>10,162</td>
</tr>
<tr>
<td>2016</td>
<td>10,077</td>
</tr>
<tr>
<td>2017</td>
<td>10,072</td>
</tr>
<tr>
<td>2018</td>
<td>10,072</td>
</tr>
<tr>
<td>2019</td>
<td>10,072</td>
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<tr>
<td>2020</td>
<td>10,072</td>
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<td>2021</td>
<td>10,072</td>
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<td>10,072</td>
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<tr>
<td>2032</td>
<td>10,072</td>
</tr>
<tr>
<td>2033</td>
<td>10,072</td>
</tr>
</tbody>
</table>

**Heritage Hydroelectric**
- Existing and Committed Heritage Resources
  - Heritage Hydroelectric: 10,182
- Resource Smart: 51
- Waneta Transaction: 256
- Mica 5: 0
- Mica 6: 0
- Ruskin: 0
- John Hart: 0

**Existing and Committed IPP Resources**
- Standing Offer Program (signed EPAs): 10
- AltaGas Power (NTL): 0
- Waneta Expansion: 0
- Integrated Power Offer: 125
- Bioenergy Call Phase II: 0
- Conifex: 0

**Future Supply-Side Resources**
- IPP Renewals: 16
- Standing Offer Program: 0
- IBAs: 0
- Revolutile Unit 6: 0
- GMS Units 1 - 5 Capacity Increase: 0
- SCGT: 0
- Clean Resources: 0

**Total Supply Requiring Reserves**
- 12,494

**Reserves**
- 14% of Supply Requiring Reserves: -1,749
- 400 MWh market reliance: 400

**Supply Not Requiring Reserves**
- Alcan 2007 EPA: 419
- Market Purchases: 0

**Effective Load Carrying Capacity**
- 11,564

### Future Demand Side Management & Other Measures

<table>
<thead>
<tr>
<th>Year</th>
<th>Future Demand Side Management Before DSM</th>
</tr>
</thead>
<tbody>
<tr>
<td>2012</td>
<td>-11,011</td>
</tr>
</tbody>
</table>

**SMI Theft Reduction**
- 0

**Voltage and VAR Optimization**
- 0

**DSS Option 2 / DSM Target**
- Differential DSM 3 to DSM 2: 304

**Industrial Load Curtailment**
- 39

**Capacity-focused DSM programs**
- 14

**Time-base rates**
- 11

**Total Capacity-focused DSM**
- 64

**Surplus / Deficit**
- 368

**2012 Mid Load Forecast Before DSM**
- 921
BRP without LNG (without Site C) – Energy (GWh)
F2014

F2015

F2016

F2017

F2018

F2019

F2020

F2021

F2022

F2023

F2024

F2025

F2026

F2027

F2028

F2029

F2030

F2031

F2032

F2033

Existing and Committed Heritage Resources
Heritage Hydroelectric

44,962

44,884

45,737

42,425

42,048

42,048

42,048

42,048

42,048

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42,048

42,048

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4,100

4,100

4,100

4,100

4,100

4,100

4,100

4,100

4,100

Heritage Thermal

31

31

31

180

180

180

180

180

180

180

180

180

180

180

180

180

180

180

180

180

Resource Smart

60

86

113

133

133

133

133

133

133

133

133

133

133

133

133

133

133

133

133

133

Heritage Hydroelectric Non-Firm / Market Allowance

Waneta Transaction

1,003

874

865

865

865

865

865

865

865

865

865

865

865

865

865

865

865

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Mica 5

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73

145

145

145

145

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145

145

145

Mica 6

0

0

28

56

56

56

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56

56

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56

56

56

56

Ruskin

0

0

30

221

319

338

338

338

338

338

338

338

338

338

338

338

338

338

338

338

John Hart

0

0

0

300

806

806

806

806

806

806

806

806

806

806

806

806

806

806

806

806

46,056

45,948

46,949

48,425

48,652

48,671

48,671

48,671

48,671

48,671

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48,671

48,671

48,671

Pre-F06 Call EPAs (incl. Rio Tinto Alcan)

7,078

6,865

4,309

5,936

5,786

5,135

4,977

4,869

4,869

2,699

2,437

2,197

2,057

1,956

1,851

1,561

1,497

1,482

1,481

1,477

F2006 Call

2,158

2,603

2,603

2,328

2,328

2,328

2,328

2,328

2,328

2,328

2,328

2,328

2,328

2,328

2,328

2,283

2,119

2,058

1,991

1,963

Standing Offer Program (signed EPAs)

214

228

228

201

201

201

201

201

201

201

201

201

201

201

201

201

197

190

187

186

Bioenergy Call Phase I

569

569

569

582

582

582

515

342

221

221

221

221

221

221

54

0

0

0

-2

-2

Clean Power Call

786

1,369

1,629

1,768

2,124

2,253

2,253

2,253

2,253

2,253

2,253

2,253

2,253

2,253

2,253

2,253

2,253

2,253

2,253

2,234

AltaGas Power (NTL)

0

593

873

947

947

947

947

947

947

947

947

947

947

947

947

947

947

947

947

947

Waneta Expansion

0

0

567

306

306

306

306

306

306

306

306

306

306

306

306

306

306

306

306

306

926

1,055

1,092

1,139

1,139

1,139

1,139

1,139

673

533

430

350

313

238

185

34

0

0

0

0

0

109

360

565

565

565

565

565

565

565

565

565

565

565

565

565

565

565

565

565

Sub-total
Existing and Committed IPP Resources

Integrated Power Offer
Bioenergy Call Phase II
Conifex

0

94

188

180

180

180

180

180

180

180

180

180

180

180

180

180

180

180

180

180

Sub-total

11,731

13,485

12,418

13,952

14,158

13,636

13,411

13,130

12,543

10,233

9,868

9,548

9,371

9,195

8,870

8,330

8,064

7,981

7,908

7,856

Total existing and committed supply

57,875

60,087

60,490

63,576

64,115

63,983

64,065

63,951

63,684

63,640

63,615

63,601

63,610

63,598

63,516

63,439

63,449

63,475

63,500

63,527
6,356

Future Supply-Side Resources
IPP Renewals

88

654

1,096

1,147

1,245

1,570

1,683

1,824

2,117

4,357

4,670

4,950

5,109

5,247

5,463

5,900

6,149

6,232

6,303

Standing Offer Program

0

0

27

52

60

106

133

159

186

212

239

265

292

318

345

371

398

424

451

477

IBAs

0

0

0

0

0

0

167

167

167

167

167

167

167

167

167

167

167

167

167

167
26

Revelstoke Unit 6

0

0

0

0

0

0

0

0

0

0

0

0

0

0

0

0

0

26

26

SCGT

0

0

0

0

0

0

0

0

0

0

0

0

0

0

0

0

0

0

0

0

CCGT

0

0

0

0

0

0

0

0

0

0

0

0

0

0

0

986

986

1,064

1,104

1,143

Clean Resources
SubTotal
Total Supply

0

0

0

0

0

0

0

0

0

0

0

0

0

0

0

0

450

1,100

1,950

2,604

88

654

1,123

1,199

1,305

1,676

1,983

2,150

2,470

4,736

5,076

5,382

5,568

5,732

5,975

7,424

8,150

9,013

10,001

10,773

57,875

60,087

60,490

63,576

64,115

63,983

64,065

63,951

63,684

63,640

63,615

63,601

63,610

63,598

63,516

64,425

64,885

65,665

66,580

67,300

-58,714

-60,378

-61,655

-63,238

-65,769

-67,545

-69,111

-70,207

-70,811

-71,721

-72,707

-73,428

-73,812

-74,512

-75,475

-76,366

-77,420

-78,433

-79,486

-80,316

562

Demand - Integrated System Total Gross Requirements
2012 Mid Load Forecast Before DSM

Future DSM & Other Measures
SMI Theft Reduction
Voltage and VAR Optimization
DSM Option 2 / DSM Target
Differential DSM 3 to DSM 2
SubTotal

0

0

0

0

65

129

193

256

318

380

442

503

562

562

562

562

562

562

562

38

162

229

273

288

304

314

326

328

329

331

333

334

336

338

339

341

343

345

346

1,919

2,668

3,564

4,364

4,942

5,893

6,842

7,790

8,202

8,423

8,947

9,186

9,590

9,862

10,196

10,274

10,505

10,746

10,906

10,995

0

0

0

152

359

544

686

675

783

1,186

1,186

1,317

1,175

1,175

1,175

1,175

1,175

1,175

1,175

1,175

1,957

2,830

3,793

4,789

5,654

6,870

8,035

9,047

9,631

10,318

10,906

11,339

11,661

11,935

12,271

12,350

12,583

12,826

12,988

13,078

170%

129%

106%

80%

78%

77%

79%

80%

79%

78%

77%

77%

76%

73%

70%

67%

65%

63%

61%

56,757

57,548

57,862

58,449

60,115

60,675

61,076

61,160

61,180

61,403

61,801

62,089

62,151

62,577

63,204

64,016

64,837

65,607

66,498

67,238

DSM as % of load growth
Annual Energy Demand After Conservation
Gas as % of load

6.1%

5.9%

5.8%

5.5%

5.5%

5.5%

5.5%

5.5%

5.5%

5.5%

5.5%

5.5%

5.5%

5.5%

5.5%

7.0%

6.9%

7.0%

6.9%

6.9%

Surplus / Deficit (GWh)

1,118

2,539

2,628

5,127

4,000

3,308

2,989

2,791

2,504

2,237

1,814

1,512

1,459

1,021

312

409

48

59

82

62


APPENDIX 2

CONTINGENCY RESOURCE PLAN (CRP) WITH LNG CAPACITY AND ENERGY BALANCES

PORTFOLIO WITHOUT SITE C
### Existing and Committed Heritage Resources

<table>
<thead>
<tr>
<th>Year</th>
<th>Heritage Hydraulics</th>
<th>Heritage Thermal</th>
<th>Resource Smart</th>
<th>Wannele Transaction</th>
<th>Mica S</th>
<th>Mica 6</th>
<th>Ruskin</th>
<th>John Hart</th>
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### Existing and Committed IP Resources

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<td>1,124</td>
<td>1,156</td>
<td>1,133</td>
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<tr>
<td>2015</td>
<td>51,335</td>
<td>1,143</td>
<td>1,124</td>
<td>1,156</td>
<td>1,133</td>
</tr>
<tr>
<td>2016</td>
<td>51,335</td>
<td>1,143</td>
<td>1,124</td>
<td>1,156</td>
<td>1,133</td>
</tr>
<tr>
<td>2017</td>
<td>51,335</td>
<td>1,143</td>
<td>1,124</td>
<td>1,156</td>
<td>1,133</td>
</tr>
<tr>
<td>2018</td>
<td>51,335</td>
<td>1,143</td>
<td>1,124</td>
<td>1,156</td>
<td>1,133</td>
</tr>
<tr>
<td>2019</td>
<td>51,335</td>
<td>1,143</td>
<td>1,124</td>
<td>1,156</td>
<td>1,133</td>
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<tr>
<td>2020</td>
<td>51,335</td>
<td>1,143</td>
<td>1,124</td>
<td>1,156</td>
<td>1,133</td>
</tr>
<tr>
<td>2021</td>
<td>51,335</td>
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<td>1,124</td>
<td>1,156</td>
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<tr>
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<td>1,143</td>
<td>1,124</td>
<td>1,156</td>
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</tr>
<tr>
<td>2023</td>
<td>51,335</td>
<td>1,143</td>
<td>1,124</td>
<td>1,156</td>
<td>1,133</td>
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### Future Supply-Side Resources

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<td>0</td>
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<tr>
<td>Clean Power Call</td>
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<td>112</td>
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<tr>
<td>AlGaA Power (NTL)</td>
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<td>0</td>
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<td>Bioenergy Call II</td>
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### Future Load Forecast Before DSM

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</tr>
<tr>
<td>2013</td>
<td>11,364</td>
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<td>11,364</td>
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### Future Demand Side Management & Other Measures

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### Energy Storage

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### RES Source

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<td>Clean Power Call</td>
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<tr>
<td>AlGaA Power (NTL)</td>
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### Emission Reduction

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### Future Load Forecast Before DSM

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<th>Year</th>
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<td>11,364</td>
</tr>
<tr>
<td>2027</td>
<td>11,364</td>
</tr>
<tr>
<td>2028</td>
<td>11,364</td>
</tr>
<tr>
<td>2029</td>
<td>11,364</td>
</tr>
<tr>
<td>2030</td>
<td>11,364</td>
</tr>
<tr>
<td>2031</td>
<td>11,364</td>
</tr>
<tr>
<td>2032</td>
<td>11,364</td>
</tr>
<tr>
<td>2033</td>
<td>11,364</td>
</tr>
</tbody>
</table>
### Existing and Committed Heritage Resources

<table>
<thead>
<tr>
<th>CRP with LNG (without Site C)</th>
<th>Energy (GWh)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Heritage Hydroelectric</td>
<td>44,962</td>
</tr>
<tr>
<td>Heritage Hydroelectric Non-Firm / Market Allowance</td>
<td>0</td>
</tr>
<tr>
<td>Heritage Thermal</td>
<td>31</td>
</tr>
<tr>
<td>Resource Smart</td>
<td>60</td>
</tr>
<tr>
<td>Waneta Transaction</td>
<td>1,003</td>
</tr>
<tr>
<td>Mica 5</td>
<td>0</td>
</tr>
<tr>
<td>Ruskin</td>
<td>0</td>
</tr>
<tr>
<td>John Hart</td>
<td>0</td>
</tr>
</tbody>
</table>

### Existing and Committed IPP Resources

| Pre-F06 Call EPAs (incl. Rio Tinto Alcan) | 7,078      |
| F2006 Call                             | 2,158      |
| Standing Offer Program (signed EPAs)    | 214        |
| Bioenergy Call Phase I                  | 569        |
| Clean Power Call                       | 786        |
| AltaGas Power (KTL)                     | 593        |
| Waneta Expansion                       | 0          |
| Integrated Power Offer                  | 926        |
| Bioenergy Call Phase II                 | 109        |
| Corix                                   | 0          |

### Future Supply-Side Resources

<table>
<thead>
<tr>
<th>Future DSM &amp; Other Measures</th>
<th>CRP with LNG (without Site C)</th>
<th>Energy (GWh)</th>
</tr>
</thead>
<tbody>
<tr>
<td>SMI Theft Reduction</td>
<td>0</td>
<td></td>
</tr>
<tr>
<td>Voltage and VAR Optimization</td>
<td>38</td>
<td></td>
</tr>
<tr>
<td>DSM Option 2 / DSM Target</td>
<td>1,857</td>
<td></td>
</tr>
<tr>
<td>DSM Option 3 to DSM 2</td>
<td>1,895</td>
<td></td>
</tr>
</tbody>
</table>

### Total existing and committed supply

<table>
<thead>
<tr>
<th>Future Supply-Side Resources</th>
<th>CRP with LNG (without Site C)</th>
<th>Energy (GWh)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Total Supply</td>
<td>59,311</td>
<td></td>
</tr>
</tbody>
</table>

### 2012 High Load Forecast Before DSM

| Expected LNG Load            | -61,207                    |

### Annual Energy Demand Before Conservation

<table>
<thead>
<tr>
<th>Annual Energy Demand Before Conservation</th>
<th>CRP with LNG (without Site C)</th>
<th>Energy (GWh)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Total gas-fired generation</td>
<td>3,520</td>
<td></td>
</tr>
<tr>
<td>Surplus / Deficit (GWh)</td>
<td>-1</td>
<td></td>
</tr>
</tbody>
</table>
APPENDIX 3 — QUALIFICATIONS

Cofounder of the Helios Centre, Philip Raphals has extensive experience in many aspects of sustainable energy policy, including least-cost energy planning, utility regulation (including transmission ratemaking) and green power certification. He is the author of numerous studies and reports and frequently appears as an expert witness in the regulatory arena.

From 1992 to 1994, Mr. Raphals was Assistant Scientific Coordinator for the Support Office of the Environmental Assessment of the Great Whale hydro project, where he coauthored a study on the role of integrated resource planning in assessing the project’s justification.31


Mr. Raphals appeared as an expert witness on behalf of Grand Riverkeeper Labrador Inc. in the hearings of the Joint Review Panel (JRP) on the Lower Churchill Generation Project, which retained many of his suggestions. He also presented testimony to the Newfoundland and Labrador Public Utilities Board in the context of its advisory hearings concerning the Muskrat Falls project.

Last year, he presented expert testimony to the Nova Scotia Utility and Review Board in the proceedings concerning the Maritime Link, on behalf of the Canadian Wind Energy Association and, for the compliance phase, the Low Power Rates Alliance.

In British Columbia, he testified on behalf of the Treaty 8 Tribal Association before the Joint Review Panel examining the proposal to build the Site C Hydroelectric Project.

For several years, Mr. Raphals chaired the advisory committee for renewable energies of the Low Impact Hydropower Institute (LIHI) in the United States, and he now sits on LIHI’s Renewable Markets Advisory Panel. He has also played a role in developing the low impact renewable electricity guideline for the Canadian Ecologo programme.

Mr. Raphals is a frequent expert witness before the Quebec Energy Board (the Régie de l’énergie du Québec). He has been qualified by the Régie de l’énergie as an expert witness with respect to transmission tariffs (FERC), issues related to the integration of wind power, security of supply with respect to hydropower, energy efficiency and avoided costs, and sustainable development criteria. In Nova Scotia, he was recognized as an expert in sustainable energy policy, including least-cost planning and utility regulation.
October 31, 2013

Dr. Harry Swain
Joint Review Panel Chair

Ms. Jocelyne Beaudet
Joint Review Panel Member

Mr. James S. Mattison
Joint Review Panel Member

In c/o Site C Clean Energy Project Joint Review Panel Secretariat

Ms. Courtney Trevis
Panel Co-Manager
Canadian Environmental Assessment Agency
22nd Floor, 160 Elgin Street
Ottawa, ON K1A 0H3

Mr. Brian Murphy
Panel Co-Manager
British Columbia Environmental Assessment Office
4th Floor, 836 Yates Street
Victoria, BC V8W 9V1

Dear Sirs and Madams:

RE: Request for Additional Information

I am writing further to the letter from the Joint Review Panel dated October 16, 2013. In its letter, the Panel set out 20 requests for additional information (Questions 75 through 95). In addition, the Panel requested supplemental information related to questions posed in the second round of information requests. BC Hydro provided Part 1 of responses to these questions on October 28, 2013, (CEAR #1640)

Part 2 of BC Hydro’s response is attached for questions 77a, 84, 85, 89, 94 and supplemental information for questions 33, 42 and 67. Please also be advised that separate correspondence has been directed to the Panel and its Secretariat regarding certain confidential information that has been provided by Aboriginal Groups. This confidential information, related to questions 75 and S67 will be provided separately.

If you have any questions, or require further information, please contact me directly at

Sincerely,

Danielle Melchior
Director, Environmental Assessment and Regulatory
Site C Clean Energy Project
JRP IR

# 77a
Request Number 77: Need for the Project

References: Vol. 1, Section 5.2.1.2, Table 5.4 ; Vol. 1, App. F, Part 1 ; Vol. 1, Section 5.5.3.4

**JRP Context:** Sensitivity analysis, and hence risk management, is not as thoroughly presented as it could be. Examples: The contribution of heritage hydro is held at 48,500 GWh/yr despite increasing precipitation due to climate change (IR 76). The 2012 load forecast says that the 2032 demand will be 3823 GWh less than the 2011 forecast, or 0.75 x Site C. A Class 3 cost estimate is expected to be within the range of -20 to +30 percent of actual cost, according to the Construction Association Cost Estimating Guide. The Canada-US exchange rate has held at 96.93 cents, despite the experience of recent decades.

**JRP Question A:** Perform sensitivity analyses that would include, alone and in reasonable combinations:

- fluctuating exchange rates, and
- project costs of 115 and 130 percent of the current $7.9 billion estimate

**BC Hydro Response**

To respond to the information request and to provide further information on sensitivity analysis and risk, BC Hydro prepared additional sensitivity scenarios to review the potential for key variables to vary from the base assumptions.

BC Hydro provided sensitivity analysis in the Evidentiary Update where the key inputs are increased or decreased around their expected values to determine the impact on the reference case presented in the Environmental Impact Statement (EIS) as amended. The Evidentiary Update sensitivity analysis consisted of eight sensitivities applied to two Project in-service dates (ISDs) and to the two alternatives resource portfolios (Clean Generation and Clean + Thermal Generation). These sensitivities included the Load Resource Balance (LRB) gap, cost of capital, market prices, Project capital costs, wind integration and multiple ISDs. BC Hydro systematically changed one variable at a time to evaluate how that change affects the results. This process allows BC Hydro to determine which variables are the most influential and which are secondary – in this case the LRB gap is the most influential, with the market price scenarios and the Project capital cost as the next largest.

For convenience, Table 24 from the Evidentiary Update is reproduced here to show the results of this sensitivity analysis. The Evidentiary Update sensitivity analysis is an appropriate stress test for the preferred alternative (i.e., the Project).
Evidentiary Update Table 24 – Benefit of the Project: Sensitivity Analysis Summary

<table>
<thead>
<tr>
<th>Difference in Present Value (PV) Cost (Portfolio without Site C minus with Site C) ($F2013 million)</th>
<th>Clean Generation Portfolios</th>
<th>Clean + Thermal Generation Portfolios</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>F2024</td>
<td>F2026</td>
</tr>
<tr>
<td>Base Case (Mid Gap, Mid-Market Price [Scenario 1], WACC Differential = 2%, Wind Integration Cost = $10/MWh)</td>
<td>630</td>
<td>880</td>
</tr>
<tr>
<td>Large Gap</td>
<td>Note 1</td>
<td>Note 1</td>
</tr>
<tr>
<td>Small Gap (WACC Differential = 1%)</td>
<td>(1,040)</td>
<td>(705)</td>
</tr>
<tr>
<td>WACC Differential = 1%</td>
<td>420</td>
<td>672</td>
</tr>
<tr>
<td>High Market Price (Scenario 3)</td>
<td>830</td>
<td>1,028</td>
</tr>
<tr>
<td>Low Market Price (Scenario 2)</td>
<td>450</td>
<td>755</td>
</tr>
<tr>
<td>Site C Capital Cost +10%</td>
<td>360</td>
<td>650</td>
</tr>
<tr>
<td>Wind Integration Cost ($15/MWh)</td>
<td>720</td>
<td>Note 1</td>
</tr>
<tr>
<td>Wind Integration Cost ($5/MWh)</td>
<td>530</td>
<td>Note 1</td>
</tr>
</tbody>
</table>

Note
1. The benefit for Site C in this scenario is expected to be higher than the comparative portfolio for the same sensitivity.

This response provides additional sensitivity analysis on the isolated effects of exchange rates and capital costs on the Project cost-effectiveness. This response also provides compound sensitivity analysis. Compound sensitivities combine sets of the variables that have the largest potential effect on cost-effectiveness, and are used to investigate more extreme potential outcomes of a decision. Given this combination of low probability conditions, these compound sensitivity scenarios are ‘tails’ and are highly unlikely. This response provides compound sensitivities reflecting the combined impacts of variability in the major drivers to Project cost-effectiveness: LRB gap, market prices and the Project capital cost.

The updated sensitivity analysis provided in this response consists of:

- The potential for the USD/CAD exchange rate to be lower or higher than the BC Hydro’s reference 0.97 USD/CAD. BC Hydro evaluated a low exchange rate scenario of 0.620 USD/CAD, and a high exchange rate scenario of 1.085 USD/CAD. These scenarios were based on historical maximum and minimum exchange rates over the past four decades. The broad range of electricity market prices reflected in the three market price scenarios described in Part 4.3 of the Evidentiary Update effectively cover potential fluctuations in exchange rates;

- The potential for capital cost to be higher than BC Hydro’s reference case. BC Hydro evaluated a 10% capital cost increase for the Project in Part 4.4 of the Evidentiary Update. In this response there are the following three additional sensitivities: (1) a 15% capital cost increase for the Project; (2) a 30% capital cost increase for the Project; and (3) a 30% capital cost increase for the Project and for the resource option alternatives.
BC Hydro provides comments on the plausibility of the requested 15% and 30% capital cost increase for the Project where the costs of all other alternatives are kept constant; - The potential for combining sensitivities of the main drivers to the cost-effectiveness of the Project, which are the size of the LRB gap; gas and electricity market price; and capital cost. BC Hydro evaluated (1) a “Compound Low” scenario, with a low-market condition, a small LRB gap and a 10% capital cost over-run for the Project; and (2) a “Compound High” scenario, with a high-market condition; a large LRB gap and a 10% capital cost under-run for the Project.

The results of this additional sensitivity analysis confirm BC Hydro’s conclusion that the Project is the preferred alternative to meet the identified need for energy and capacity within BC Hydro’s planning period.

The additional sensitivity analysis results along with the considerations and assumptions used are described below.

BC Hydro has also provided additional analysis on Demand Side Management (DSM) in Attachment 1. This consists of the sensitivity of changes to DSM Target performance – specifically the implications of DSM over- or under-delivery, and the relationship of DSM delivery to the large and small LRB gap analysis.

1. Exchange Rates

Exchange rates have the potential to affect the analysis of alternatives to the Project in two main ways:
- Through changes to the market price for electricity and natural gas
- Through changes to the capital costs of the Project and alternative resource options.

At page 45 of the Evidentiary Update BC Hydro stated that “market prices are the primary way in which foreign exchange rates can influence the portfolio analysis – the market price scenarios used in the sensitivity analysis are sufficiently broad to also effectively cover potential fluctuations in exchange rates”. As discussed in the response to Joint Review Panel (JRP) Information Request (IR) 25, “BC Hydro has no evidence to suggest that exchange rates are linked to the other market price uncertainties (natural gas prices, greenhouse gas (GHG) emission regulations) in a way that would result in an appreciable increase in the market price ranges. Additional uncertainties combined with other independent existing and significant uncertainties would not be expected to have a significant impact on the overall distribution”.

To address the request from the JRP, BC Hydro provided an additional sensitivity analysis that isolates potential variability in U.S. – Canadian exchange rates. In addition to the inclusion of exchange rate uncertainty in the market price scenarios, the potential for exchange rates to vary was also considered in the development of the contingency amounts included in the Project capital cost. The portion of Project costs that would be purchased in foreign currency and the potential for exchange rate fluctuations to affect the cost of this portion was included in the “Precision of Estimate” component of the contingency. Please refer to the discussion of capital cost sensitivities below for further discussion of the contingency amounts.

1 Note that the two main drivers of variability in the LRB gap are the load forecast and DSM deliverability.
In this analysis a historical range in exchange rates is applied on top of the base case market scenario (i.e., Market Scenario 1). To develop the minimum and maximum exchange rates, BC Hydro reviewed historical U.S. - Canadian exchange rates for the period from August 16, 1971 (when the U.S. effectively dropped the gold standard) to September 30, 2013. The minimum exchange rate over this period was about 0.620 (on January 18, 2002). The maximum exchange rate over this period was about 1.085 (on November 6, 2007). Please refer to Figure 1 for historical exchange rates.

Applying the full range of historical exchange rates to the Project capital cost result in capital cost variance less than 6%\(^2\). As a result, this potential variability is captured in the capital cost sensitivity analysis provided later in this response. Based on this, the sensitivity analysis of exchange rates presented here does not include any changes to the capital costs of the Project or other resource options. It is important to note that while a change to exchange rate may affect the Project capital costs, it will also affect the capital cost of alternative resource options. As a result, this sensitivity analysis isolates the effect of exchange rate on market prices only.

Table 1 below shows the results of the exchange rate sensitivity analysis.

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\(^2\) The total amount of the Project direct construction costs subject for foreign exchange rates (both USD and other currency) is $550 million (in Canadian dollars), which represents \(\sim 11\%\) of the total construction and development costs (excluding contingency).
Table 1 – Sensitivity of Project Benefit to Exchange Rate

<table>
<thead>
<tr>
<th>Difference in PV Cost (Portfolio without the Project minus Portfolio with the Project) ($F2013 million)</th>
<th>Clean Generation Portfolios F2024</th>
<th>Clean Generation Portfolios F2026</th>
<th>Clean + Thermal Generation Portfolios F2024</th>
<th>Clean + Thermal Generation Portfolios F2026</th>
</tr>
</thead>
<tbody>
<tr>
<td>Base Case (0.97 USD/CAD Exchange Rate)</td>
<td>630</td>
<td>880</td>
<td>150</td>
<td>390</td>
</tr>
<tr>
<td>0.62 USD/CAD Exchange Rate</td>
<td>950</td>
<td>Note 1</td>
<td>570</td>
<td>Note 1</td>
</tr>
<tr>
<td>1.085 USD/CAD Exchange Rate</td>
<td>570</td>
<td>Note 1</td>
<td>90</td>
<td>Note 1</td>
</tr>
</tbody>
</table>

Note:
1. The benefit of the Project in this scenario is expected to be higher than the comparative portfolio for the same sensitivity.

An exchange rate of 0.62 USD/CAD would result in a higher portfolio PV benefits for the Project over alternative portfolios. A lower exchange rate results in higher market prices in Canadian dollars for exports to U.S. markets, which in turn results in higher revenues for the export of any short-term surplus associated with the Project.

An exchange rate of 1.085 USD/CAD would result in a lower portfolio PV benefits for the Project over alternative portfolios. A higher exchange rate results in lower market prices in Canadian dollars for exports to U.S. markets, which in turn results in lower revenues for the export of any short-term surplus associated with the Project. This high exchange rate sensitivity is captured within Market Scenario 2 (low market prices) included in Table 24 of the Evidentiary Update.

2. Capital Cost Sensitivities

For the purposes of this response BC Hydro assumes that the reference to the “Construction Association Cost Estimating Guide” refers to the AACE International Recommended Practice No. 69R-12: Cost Estimate Classification System as Applied in Engineering, Procurement, and Construction for the Hydro Power Industry3 (“the AACEI Practice”).

As per the AACEI Practice, the range of accuracy of a Class 3 estimate is -10% to -20% on the low side, and +10% to +30% on the high side depending on the technological complexity of the project, appropriate reference information, and other risks (after inclusion of an appropriate contingency determination)4. As a result, the specific accuracy range applied to a cost estimate is dependent on both the estimating methodology and the characteristics of the Project. BC Hydro believes that, given the characteristics of the Project and the state of the Project design

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3 AACE International Recommended Practice No. 69R-12, page 3 of 14.
4 Please refer to BC Hydro’s responses to IRs ab_0001-170 (dated 8 May 2013, CEAR #1423) and JRP 27-B
at the time of estimation, the use of a +10% capital cost sensitivity is appropriate for the analysis of the Project compared to alternatives. The reasons for the use of a +10% capital cost sensitivity in the analysis of alternatives to the Project include:

**Maturity Level of Project Design:** At the time of the preparation of the Project cost estimate, the maturity level of project definition deliverables for major components of the Project was at the high end of the AACE guidelines for a Class 3 estimate.

- Drawings were complete for all major project components, enabling detailed quantity take-offs and analysis of Project logistics. This provided a high degree of resolution in development of the cost estimate.
- For areas where design assumptions had not been finalized, estimators adopted conservative assumptions reflecting the highest cost impact of potential future design decisions.
- As a result of this high level of definition, the capital cost estimate was prepared using a “bottom-up” deterministic methodology, utilizing individual line items for quantities and unit costs required for Project construction.

**Inclusion of Contingency:** The Project cost estimate includes an appropriate level of contingency ($730 million in real dollars) that recognized the remaining uncertainty in Project components.

- BC Hydro reviewed the level of Project design and remaining uncertainty for each Project component individually, and considered risks within the following categories:
  - Technical Content (level of precision of design and associated quantity take-offs)
  - Precision of Estimate (productivities, equipment selection, material costs and market variations)
  - Schedule (acceleration of activities to maintain overall schedule)
  The contingency for individual Project components ranged between 15% and 36%.
- The overall contingency for the direct construction costs was then estimated using a Monte Carlo analysis. The contingency adopted (18% on direct construction costs) was the upper 90th percentile provided by the Monte Carlo analysis as rounded to the nearest 1%.
- Please note that capital cost sensitivity analysis conducted in the Evidentiary Update and this response are performed compounded on top of the Project contingency.

**Mature Technology:** Hydro-electric generation facilities are a mature technology with established estimating techniques.

- As shown in Table 1 of Volume 1 Appendix F Part 1 of the EIS as amended, a significant portion of Project costs are associated with earth moving activities which have limited technical risk.
- The main technical risk to the Project comes from geotechnical risk associated with foundation conditions. Historical site investigations over the past several decades have allowed BC Hydro to develop a Project design to minimize these geotechnical risks.

**Review and Project Controls:** BC Hydro undertook both internal and external reviews of the cost estimate, and is continuing to manage costs to remain within the estimated capital costs.

- The capital cost estimate was developed by the Project’s Integrated Engineering Team, who has extensive recent experience with hydro-electric project construction.
The capital cost estimate underwent review by BC Hydro estimators and external construction advisors.

The capital cost estimate underwent an external peer review by KPMG who concluded that the methodologies and assumptions used in the cost estimate were appropriate.

BC Hydro monitors capital cost drivers on a regular basis, and has established a project management process to maintain project costs within the capital cost estimate.

Given the level of scope definition for the Project, a situation where Project capital costs increase by 30% is highly unlikely outside of a scenario where there is a market disruption – i.e., an external, systemic increase to one or more major Project cost drivers (such as labour costs or steel prices). Importantly, a change to such a cost driver would not only apply to the Project, but would also affect all other resources options under consideration in the analysis of alternatives. Thus a sensitivity in which Project capital costs are increased by 30% and the capital costs of all other alternatives are held constant is not plausible because alternatives would be subject to the same market disruption as the Project. Nevertheless, to be responsive BC Hydro has provided the requested analysis where the Project’s costs are increased by 15% and 30% while the cost of all other alternatives remains constant.

To provide analysis of the potential consequences of a market disruption, BC Hydro conducted sensitivity analysis showing the cost-effectiveness of the Project in a scenario where both the Project and alternatives experience a 30% increase in cost. This 30% sensitivity is at the far end of the range of a Class 3 estimate but less than the far end of the range of the Class 4 and 5 estimates for alternative resource options. Given the lack of specific design and site information for the Class 4 and 5 alternatives it is possible the cost impacts for alternative resource options could be higher.

This overall capital cost increase will affect the Project and the resource options differently depending on the proportion of the resource’s levelized costs (i.e., Unit Energy Cost (UEC)) that comes from capital costs versus operating costs. For example, as shown in Table 7.2 of the EIS as amended approximately 90% of the Project’s UEC comes from capital costs, and as a result the Project UEC will be more sensitive to capital cost variations than other resource options with a lower proportion of capital costs. In contrast, alternatives such as natural gas-fired generation are more sensitive to operating cost impacts such as fuel (natural gas) price fluctuations and GHG compliance instrument costs.

Table 2 below summarizes the portfolio PV results of the capital cost sensitivity analysis.
Table 2 – Sensitivity of Project Benefit to Capital Cost Increase

<table>
<thead>
<tr>
<th>Difference in PV Cost (Portfolio without the Project minus Portfolio with the Project) ($F2013 million)</th>
<th>Clean Generation Portfolios</th>
<th>Clean + Thermal Generation Portfolios</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>F2024</td>
<td>F2026</td>
</tr>
<tr>
<td>Base Case</td>
<td>630</td>
<td>880</td>
</tr>
<tr>
<td>Site C 10% Capital Cost Increase, all other alternatives held constant</td>
<td>360</td>
<td>650</td>
</tr>
<tr>
<td>Project 15% Capital Cost Increase, all other alternatives held constant</td>
<td>250</td>
<td>560</td>
</tr>
<tr>
<td>Site C 30% Capital Cost Increase, all other alternatives held constant</td>
<td>(100)</td>
<td>270</td>
</tr>
<tr>
<td>Site C and Alternative Resource Options 30% Capital Cost Increase</td>
<td>600</td>
<td>950</td>
</tr>
</tbody>
</table>

Table 3 below summarizes the adjusted UEC results of the block analysis for the same capital cost sensitivities described above.
Table 3 – Sensitivity of Adjusted UEC Block Analysis to Capital Cost Increase ($/MWh, $F2013)

<table>
<thead>
<tr>
<th>Adjusted UEC ($F2013/MWh)</th>
<th>Project (note 1)</th>
<th>Clean Generation</th>
<th>Clean + Thermal Generation</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td></td>
<td>Block #1</td>
<td>Block #2</td>
</tr>
<tr>
<td></td>
<td></td>
<td>(Revelstoke Unit 6 and Six Simple Cycle Gas Turbines (SCGTs))</td>
<td>(Revelstoke Unit 6, GMS and 4 SCGTs)</td>
</tr>
<tr>
<td>Base Case</td>
<td></td>
<td>94</td>
<td></td>
</tr>
<tr>
<td>Site C 10% Capital Cost Increase</td>
<td>101</td>
<td>153</td>
<td>128 130</td>
</tr>
<tr>
<td>Site C 15% Capital Cost Increase</td>
<td>105</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Site C 30% Capital Cost Increase</td>
<td>116</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Site C and Resource Options 30% Capital Cost Increase</td>
<td>116</td>
<td>184</td>
<td>154 Note 2</td>
</tr>
</tbody>
</table>

Note:
1. The Adjusted UEC for the Project would decrease by about $2/MWh to reflect the seasonal, daily and hourly shaping capability of the Project.
2. The Adjusted UEC for Block #2 will be higher than the adjusted UEC for Block #1 for the Project and Resource Options 30% Capital Cost Increase sensitivity.

As shown in Table 2, an increase in the Project capital costs would result in a decrease in the portfolio PV differential.

- **+15% Project Capital Costs, Alternatives Held Constant:** The Project remains cost-effective compared to the Clean portfolio at both ISDs. Compared to the Clean+Thermal portfolio the Project remains cost-effective at a F2026 ISD but is not cost-effective compared at a F2024 ISD.
- **+30% Project Capital Costs, Alternatives Held Constant:** Compared to the Clean portfolio the Project remains cost-effective at a F2026 ISD but is not cost-effective compared at a F2024 ISD. The Project is not cost-effective compared to a Clean+Thermal portfolio at both ISDs.
- **+30% for both Project and Alternative Capital Cost:** The Project remains cost-effective compared to the Clean portfolio at both ISDs. Compared to the Clean+Thermal portfolio the Project remains cost-effective at a F2026 ISD but is not cost-effective compared at a F2024 ISD.
- **UEC Block Analysis:** The UEC block analysis shown in Table 3. As shown, the Project has a lower UEC than the Clean and Clean+Thermal blocks in all capital cost sensitivities. This indicates that the Project has a lower cost than a comparable block of alternative resources providing 5,100 GWh/year and 1,100 MW.
3. Compound Sensitivities

In Part 4 of the Evidentiary Update, BC Hydro systematically changed one variable at a time to see how that change affects the results. The process allows BC Hydro to determine which variable are important and which are secondary. The variability in PV benefits due to the LRB gap is significantly larger than due to any other sensitivity. The next largest sensitivities are the market price scenarios and the Project capital cost.

BC Hydro conducted further analysis of the potential compound impacts of these main drivers to the cost-effectiveness of the Project. One of the main issues with compound sensitivity analysis is that, in practice, it is difficult to quantify how individual items fluctuate together. For example, while there is likely a strong correlation between a large gap and higher commodity and labour prices (which impact Project cost) it is less certain how the large LRB gap/small LRB gap and high market price/low market price scenarios correlate. In the absence of evidence concerning covariance, the starting point for combined sensitivities is to assume that each sensitivity is independent. As a result, BC Hydro identified the conditions that will influence a large portion of the Project and treated them individually in Part 4 of the Evidentiary Update.

As shown in Table 24 of the Evidentiary Update, the primary driver of the difference in PV cost between portfolios with and without the Project is the LRB gap. To provide a robust range of sensitivity scenarios, BC Hydro evaluated the difference in PV costs between portfolios at the extremes of the potential future scenarios. Specifically:
- A “Compound Low” scenario, with a low-market condition (i.e., Market Scenario 2) and a small LRB gap condition as well as a 10% capital cost overrun.
- A “Compound High” scenario, with a high-market condition (i.e., Market Scenario 3) and a large LRB gap condition as well as a 10% under-run on the Project capital costs.

These scenarios represent the far ends of the potential probability distribution and are highly unlikely. For example, in the Evidentiary Update, BC Hydro assessed the probability of the small gap scenario at about 10%, and the low market scenario (Market Scenario 2) at a 20% likelihood. If these two scenarios are treated as independent the probability would be about 2%.

The Compound Low is the scenario with the highest level of regret for the decision to build the Project, while the Compound High is the scenario with the highest level of regret for a decision to not build the Project (and to build the Clean or Clean + Thermal portfolios instead).

The Compound Low contains the small LRB gap scenario, which is a low likelihood scenario that would effectively see negligible load growth after DSM for the relevant portion of the planning period (about 4,900 GWh net growth from F2014 to F2033 compared to 11,700 GWh of net growth under the mid load mid DSM reference case for the same time period).

Table 4 below summarizes the results of the compound sensitivity analysis.
### Table 4 – Compound Sensitivities for LRB Gap, Market Price and Site C Capital Cost

<table>
<thead>
<tr>
<th>Difference in PV Cost (Portfolio without the Project minus Portfolio with the Project) ($F2013 million)</th>
<th>Clean Generation Portfolios</th>
<th>Clean + Thermal Generation Portfolios</th>
</tr>
</thead>
<tbody>
<tr>
<td>Base Case (Mid Gap, Mid-Market Price [Scenario 1], Reference Site C Capital Cost)</td>
<td>630</td>
<td>880</td>
</tr>
<tr>
<td>Compound Low Scenario (Small Gap, Low Market Price [Scenario 2], 10% Site C Capital Cost Increase)</td>
<td>Note 1</td>
<td>Note 1</td>
</tr>
<tr>
<td>Compound High Scenario (Large Gap, High Market Price [Scenario 3], 10% Site C Capital Cost Decrease)</td>
<td>Note 1</td>
<td>Note 1</td>
</tr>
</tbody>
</table>

**Note:**
1. The difference in PV cost in this scenario is expected to be higher than the difference in PV cost in the Clean + Thermal Generation Portfolios for the same sensitivity.
2. The difference in PV cost in this scenario is expected to be higher than the difference in PV cost in the Clean + Thermal Generation Portfolio with a F2024 in-service date for the Project.

As shown in Table 4, the results of the compound sensitivity analysis are consistent with the results of the large and small LRB gap sensitivity analysis in Part 4.1 of the Evidentiary Update. Due to the compounded effects of market price conditions and capital cost variation, the Compound Low scenario has lower portfolio PV benefits for the Project over alternative portfolios than the small gap scenario (-2,000 vs. -1,280). Likewise, the Compound High scenario has higher portfolio PV benefits for the Project over alternative portfolios than the large gap scenario (+2,610 vs. 2,260).
4. Summary

The sensitivity analysis conducted in Part 4 of the Evidentiary Update reviewed the cost-effectiveness of the Project under variability in LRB gap, market prices, Weighted Average Cost of Capital differentials, capital costs, and wind integration costs. This analysis showed that the Project provides benefits compared to alternatives not only in the reference case, but also in a wide range of potential scenarios. The additional sensitivity analysis provided in this response reviews the cost-effectiveness of the Project in additional low probability scenarios. These additional sensitivity scenarios confirm BC Hydro’s conclusion that the Project is the preferred alternative to meet the identified need for energy and capacity within BC Hydro’s planning period – the scenarios in which alternative portfolios provide benefits compared to the Project are generally low probability and are associated with long-term low load growth or market prices. Table 5 updates the summary table of sensitivity analysis with the new scenarios.

Table 5 – Benefit of the Project: Updated Sensitivity Analysis Summary

<table>
<thead>
<tr>
<th>Difference in PV Cost (Portfolio without Site C minus with Site C) ($F2013 million)</th>
<th>Clean Generation Portfolios</th>
<th>Clean + Thermal Generation Portfolios</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>F2024</td>
<td>F2026</td>
</tr>
<tr>
<td>Base Case (Mid Gap, Mid-Market Price [Scenario 1], WACC Differential = 2%, Wind Integration Cost = $10/MWh)</td>
<td>630</td>
<td>880</td>
</tr>
<tr>
<td>Large Gap</td>
<td>Note 1</td>
<td>Note 1</td>
</tr>
<tr>
<td>Small Gap</td>
<td>(1,040)</td>
<td>(705)</td>
</tr>
<tr>
<td>High Market Price (Scenario 3)</td>
<td>830</td>
<td>1,028</td>
</tr>
<tr>
<td>Low Market Price (Scenario 2)</td>
<td>450</td>
<td>755</td>
</tr>
<tr>
<td>0.62 USD/CAD Exchange Rate</td>
<td>950</td>
<td>Note 1</td>
</tr>
<tr>
<td>1.085 USD/CAD Exchange Rate</td>
<td>570</td>
<td>Note 1</td>
</tr>
<tr>
<td>Site C Capital Cost +10%, alternatives held constant</td>
<td>360</td>
<td>650</td>
</tr>
<tr>
<td>Site C Capital Cost +15%, alternatives held constant</td>
<td>250</td>
<td>560</td>
</tr>
<tr>
<td>Site C Capital Cost +30%, alternatives held constant</td>
<td>(60)</td>
<td>270</td>
</tr>
<tr>
<td>Site C and Alternative Resource Options Capital Cost +30%</td>
<td>600</td>
<td>950</td>
</tr>
<tr>
<td>WACC Differential = 1%</td>
<td>420</td>
<td>672</td>
</tr>
<tr>
<td>Wind Integration Cost ($15/MWh)</td>
<td>720</td>
<td>Note 1</td>
</tr>
<tr>
<td>Wind Integration Cost ($5/MWh)</td>
<td>530</td>
<td>Note 1</td>
</tr>
<tr>
<td>Compound Low Scenario (Small Gap, Low Market Price, 10% Site C Capital Cost Increase)</td>
<td>Note 1</td>
<td>Note 1</td>
</tr>
<tr>
<td>Compound High Scenario (Large Gap, High Market Price, 10% Site C Capital Cost Decrease)</td>
<td>Note 1</td>
<td>Note 1</td>
</tr>
</tbody>
</table>

Note
1. The benefit for Site C in this scenario is expected to be higher than the comparative portfolio for the same sensitivity.
It is possible to construct additional sensitivity scenarios to those represented above, however these scenarios will likely fall within the extreme bounds described in the Compound Sensitivity scenarios and would be expected to reach the same conclusion – that given the wide range of potential scenarios in which the Project provides benefits compared to alternatives, and given the low likelihood of the scenarios in which it does not, the Project is the preferred resource option to meet BC Hydro’s forecast customer demand.
Attachment 1 – Demand-Side Management Deliverability Risk and Link to Large and Small Gap Sensitivity Analysis

As part of its Integrated Resource Planning (IRP) process, BC Hydro evaluates the DSM deliverability risk qualitatively and quantitatively. As discussed in section 4.1 of the Evidentiary Update BC Hydro prepared an uncertainty assessment of the DSM Target and developed high and low DSM delivery bands. The uncertainty analysis focuses on quantifying the range of possible outcomes for the three broad DSM categories of (1) DSM programs, (2) codes and standards, and (3) rate structures. By combining all of the quantified sources of uncertainty in a Monte Carlo analysis and adjusting based on professional judgment, BC Hydro produced a quantified range of uncertainty around mid-level DSM estimates for F2021 and F2029 and interpolated and extrapolated across the planning horizon for the remaining years.

Figure 2 and Figure 3 show the results of this assessment.

Figure 2 – Range of Potential Energy Savings for DSM Target
Figure 3 – Range of Associated Capacity Savings for DSM Target

The assumption made in this analysis is that uncertainty grows in a linear way. This assumption is likely incorrect, as uncertainty usually grows in a non-linear way into the future, a factor not captured in this uncertainty analysis. BC Hydro is of the view that given the aggressiveness of the DSM Target, there is likely more risk of under-delivery than of over-delivery.

Table 6 and Table 7 show the variation in the DSM Target for the low and high uncertainty band in F2021, F2024 and F2026 for energy and capacity consistent with Figure 2 and Figure 3.

Table 6 – Variation from DSM Target of Potential Energy Savings (GWh)

<table>
<thead>
<tr>
<th></th>
<th>F2021</th>
<th>F2024</th>
<th>F2026</th>
</tr>
</thead>
<tbody>
<tr>
<td>DSM Low Uncertainty Band</td>
<td>(2,405)</td>
<td>(2,726)</td>
<td>(2,919)</td>
</tr>
<tr>
<td>DSM High Uncertainty Band</td>
<td>1,818</td>
<td>2,051</td>
<td>2,171</td>
</tr>
</tbody>
</table>

Table 7 – Variation from DSM Target of Associated Capacity Savings (MW)

<table>
<thead>
<tr>
<th></th>
<th>F2021</th>
<th>F2024</th>
<th>F2026</th>
</tr>
</thead>
<tbody>
<tr>
<td>DSM Low Uncertainty Band</td>
<td>(313)</td>
<td>(374)</td>
<td>(415)</td>
</tr>
<tr>
<td>DSM High Uncertainty Band</td>
<td>363</td>
<td>415</td>
<td>445</td>
</tr>
</tbody>
</table>
Table 8 and Table 9 show the variation in the size of the mid gap for the small gap and the large gap sensitivity analysis in F2021, F2024 and F2026.

<table>
<thead>
<tr>
<th></th>
<th>F2021</th>
<th>F2024</th>
<th>F2026</th>
</tr>
</thead>
<tbody>
<tr>
<td>Small Gap</td>
<td>(4,949)</td>
<td>(5,445)</td>
<td>(5,520)</td>
</tr>
<tr>
<td>Large Gap</td>
<td>10,401</td>
<td>11,536</td>
<td>12,061</td>
</tr>
</tbody>
</table>

Table 9 – Variation in the Mid Gap for the Small Gap and the Large Gap - Capacity (MW)

<table>
<thead>
<tr>
<th></th>
<th>F2021</th>
<th>F2024</th>
<th>F2026</th>
</tr>
</thead>
<tbody>
<tr>
<td>Small Gap</td>
<td>(676)</td>
<td>(744)</td>
<td>(783)</td>
</tr>
<tr>
<td>Large Gap</td>
<td>1,368</td>
<td>1,567</td>
<td>1,699</td>
</tr>
</tbody>
</table>

As discussed in the response to JRP IR 25, BC Hydro plans resource acquisition based on its mid-load forecast for the reasons set out in Section 5.2.1.1 of the EIS as amended. The values above show that the requirements for a mid-gap scenario with DSM over-delivery and a mid-gap scenario with DSM under-delivery are captured by the Small Gap and Large Gap sensitivity analysis provided in Part 4.1 of the Evidentiary Update. This means that the Small Gap and Large Gap portfolio PV analysis also covers the range of PV results for the DSM under-delivery and over-delivery scenarios.

Table 10 demonstrates historic DSM savings since 2009 and shows that DSM has not either under- or over-delivered to the extent set out in Table 6 and Table 7 above. The year 2009 is chosen because this is the year the DSM Target was introduced and the DSM Target is a significant step up from DSM targets BC Hydro set before 2009.5

<table>
<thead>
<tr>
<th></th>
<th>DSM Plan</th>
<th>Actual</th>
</tr>
</thead>
<tbody>
<tr>
<td>F2009</td>
<td>678</td>
<td>1,295</td>
</tr>
<tr>
<td>F2010</td>
<td>1,540</td>
<td>1,909</td>
</tr>
<tr>
<td>F2011</td>
<td>2,349</td>
<td>2,314</td>
</tr>
<tr>
<td>F2012</td>
<td>3,310</td>
<td>3,528</td>
</tr>
<tr>
<td>F2013</td>
<td>4,439</td>
<td>4,460</td>
</tr>
</tbody>
</table>

5 Refer to BC Hydro’s response to IR ab_0001-033 (dated 8 May 2013, CEAR #1423).
<table>
<thead>
<tr>
<th>IR</th>
<th>Organization</th>
<th>EIS Section</th>
<th>Information Request</th>
<th>BCH Response</th>
</tr>
</thead>
</table>
| ab_0001-033 | Treaty 8 Tribal Association | V.1, S.5.2 ; page(s) 5-3; line(s) 39-40 EISG S.4.1.1 | **Comment 1-18.**  
*DSM delivery risk – the risk that the response to DSM is less than planned or required*  
**Comments** No mention is made of the possibility that response to DSM might be greater than planned.  
**Information Request** The Proponent is requested to: a) evaluate the implications of scenarios where response to DSM is greater than planned, including descriptions of these scenarios and detailed results; b) indicate whether and when prior response to DSM in BC Hydro’s service territory has been greater than planned, including detailed data, past projections of DSM performance as well as actual response for each year; and c) provide examples of other jurisdictions in Canada or the US where response to DSM has been greater than planned, including details as to the year of the projection, the year-by-year projected results and the corresponding actual results. | Past performance with respect to meeting past Demand-side Management (DSM) targets is not likely to be indicative of the delivery risk associated with the current DSM target because the current DSM target is a significant step up from DSM targets BC Hydro set before 2009. Given BC Hydro’s reliance on the current DSM target to deliver 1,400 MW of anticipated dependable capacity savings in about an eight year timeframe, there is a greater consequence if the response to DSM programs and other initiatives is less than anticipated, as compared to a scenario where the response is greater than anticipated.  
The information requested to “provide examples of other jurisdictions in Canada or the US where response to DSM has been greater than planned, including details as to the year of the projection, the year-by-year projected results and the corresponding actual results” is outside the scope of the environmental assessment as it is not relevant to a determination of the need for the Project.  
Please see the following Technical Memos  
– Project Need  
– Demand-side Management |

<table>
<thead>
<tr>
<th>IR</th>
<th>Organization</th>
<th>EIS Section</th>
<th>Information Request</th>
<th>BCH Response</th>
</tr>
</thead>
</table>
| ab_0001-170 | Treaty 8 Tribal Association | V.1, Appendix F, Part 1; page(s) 2; line(s) n/a EISG S.5 | Comment 1-155.  
*Due to engineering, environmental, and consultation work done in previous stages of the Project, the Project had reached a level of project definition to characterize the $7.9 billion project cost estimate as a Class 3 cost estimate as defined by the Association for the Advancement of Cost Engineering (AACE 2012).*

**Information Request** The Proponent is asked to provide: a) the range of accuracy of a Class 3 cost estimate; and b) the upper and lower bounds of this Class 3 capital cost estimate.  
From the AACE classification, "Typical accuracy ranges for Class 3 estimates are -10% to -20% on the low side, and +10% to +30% on the high side, depending on the technological complexity of the project, appropriate reference information, and other risks (after inclusion of an appropriate contingency determination)."
Site C Business Case Assumptions Review

ROBERT MCCULLOUGH
PRINCIPAL
MCCULLOUGH RESEARCH

MAY 25, 2015
May 25, 2015

Mr. Ken Boon
President, Peace Valley Landowners Association
SS #2, Site 12, Comp 19
Fort St. John, BC V1J4M7

Dear Mr. Boon:

Please find attached our review of the pivotal assumptions behind the voluminous economic studies developed in the course of the Site C selection. Please note that we have not made a suggestion for the future energy plans of British Columbia. Instead, we did something that should have been done several years ago by comparing the pivotal assumptions that can “place a thumb on the scale” in the ultimate choice.

In the course of our review we have found evidence from the U.S. Bonneville Power Administration that suggests that British Columbia Hydro’s choice of a discount rate may have differed from their usual practice. Since this is the single most important assumption in any cost benefit study, a careful review of BC Hydro’s decision to use this discount rate is in order.

Yours,

[Signature]

Robert McCullough
On December 16, 2014, the Government of British Columbia announced its decision to approve the Site C dam. For industry participants, it was a surprising conclusion that a relatively high-cost hydroelectric project was reported to be two-thirds the cost of the alternatives. Considering actual costs in the industry across North America, the decision implied a heavy “finger on the scale” in favor of Site C.

A month later, on January 16, 2015, Les MacLaren, the Assistant Deputy Minister of the Electricity and Alternative Energy Division of the Office of the Ministry of Energy and Mines issued a report entitled “Site C Clean Energy Project Due Diligence Review.” In a few pages the report summarized the justification of Site C, a major hydroelectric project on the Peace River.

The research in defense of this controversial project is comprised of hundreds, if not thousands, of documents totaling thousands of pages. Assistant Deputy Minister MacLaren summarized the analysis in a single table:

<table>
<thead>
<tr>
<th></th>
<th>Site C (2014)</th>
<th>IPPs (Industry Consultations)</th>
<th>IPPs (IRP)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Starting Cost</td>
<td>$58 - $61 / MWh</td>
<td>$85 / MWh</td>
<td>$96 / MWh</td>
</tr>
<tr>
<td>Additional Factors</td>
<td>Adds $6</td>
<td>Adds $25</td>
<td>Adds $34</td>
</tr>
<tr>
<td>Final Cost</td>
<td>$64 - $67 / MWh</td>
<td>$110 / MWh - $130 / MWh</td>
<td></td>
</tr>
</tbody>
</table>

---

Comparing Unit Energy Costs of Site C and IPPs

<table>
<thead>
<tr>
<th>Unit Energy Cost (UEC) at Point of Interconnection</th>
<th>Site C</th>
<th>IPPs BCH 2013 IRP</th>
<th>IPPs CEBC 2014</th>
</tr>
</thead>
<tbody>
<tr>
<td>Rates Plan UEC at Point of Interconnection</td>
<td>$58-61/MW.h</td>
<td>$96/MW.h</td>
<td>$85/MW.h</td>
</tr>
<tr>
<td>Sunk Costs</td>
<td>Subtracts $4</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Line Losses</td>
<td>Adds $6</td>
<td>Adds $10</td>
<td>Adds $10</td>
</tr>
<tr>
<td>Area Transmission</td>
<td>$0</td>
<td>Adds $6</td>
<td>Adds $6</td>
</tr>
<tr>
<td>Cost of Firm Transmission</td>
<td>Adds $6</td>
<td>Adds $2</td>
<td>Adds $2</td>
</tr>
<tr>
<td>Foregone exports</td>
<td>Not Applicable</td>
<td>Adds $9</td>
<td>Adds $5</td>
</tr>
<tr>
<td>Firm Energy Adjustment (seasonal)</td>
<td>Subtracts $2</td>
<td>Subtracts $2</td>
<td>Subtracts $2</td>
</tr>
<tr>
<td>EA, permitting, FN and community benefit costs</td>
<td>Included</td>
<td>Adds $5</td>
<td>Included</td>
</tr>
<tr>
<td>Cost of Capacity Backup</td>
<td>Not applicable</td>
<td>Adds $5</td>
<td>Adds $5</td>
</tr>
<tr>
<td><strong>Unit Energy Cost Delivered to Lower Mainland:</strong></td>
<td><strong>$64-67/MW.h</strong></td>
<td><strong>$130/MW.h</strong></td>
<td><strong>$110/MW.h</strong></td>
</tr>
</tbody>
</table>

How did the decision to build Site C come down to the comparison of just two numbers – $58 to $61/MWh for Site C – to the surprisingly large value of $96/MWh for the alternatives?4

Decisions elsewhere in the U.S. and Canada have tended to rely on renewables – like wind, solar, and geothermal – for energy and natural gas for capacity. Hydro-Quebec, for example, recently announced resumed operations at Becancour, a 500 MW natural gas facility, to provide complementary capacity in support of its extensive wind development.5 While the purpose of this report is to focus on assumptions and does not attempt to reproduce the full integrated resource plan, it is logical to assume that correcting the assumptions might well bring the plan back into conformity with similar plans elsewhere.

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3 Ibid., page 8.
4 All dollar amounts in this report are 2013 Canadian dollars.
5 Use of Bécancour generating station during peak hours: Hydro-Québec Distribution reaches agreements with TransCanada and Gaz Métro, Hydro-Québec, May 8, 2015.
The 2013 Integrated Resource Plan (IRP) identified hundreds of different options and calculated a levelized per-megawatthour cost for each one. The twenty most cost-effective are:

The levelized real cost per megawatthour is called the “Unit Energy Cost” or UEC. Site C and a 500 MW combined cycle natural gas unit are indicated in red.6

The lowest cost resources are of a variety of types:

6 The Site C costs reported in BC Hydro’s publicity reflect a different issue. The 2013 Integrated Resource Plan reflects cost. Lower numbers, reported later, reflect rate design.
The UEC for Site C is $83/MWh. This differs markedly from the value given by Assistant Deputy Minister MacLaren. The difference is that MacLaren was referencing a decision by the government of British Columbia to charge less than cost for a number of years. The actual cost, however, is a real cost and will be paid by taxpayers and ratepayers. The following chart shows the rate adjustment:

<table>
<thead>
<tr>
<th>Plant types for 20 lowest cost RODAT options</th>
<th>Fuel</th>
</tr>
</thead>
<tbody>
<tr>
<td>250 MW Combined</td>
<td>natural gas</td>
</tr>
<tr>
<td>50 MW Combined Cycle</td>
<td>natural gas</td>
</tr>
<tr>
<td>500 MW Combined</td>
<td>natural gas</td>
</tr>
<tr>
<td>750 MW Integrated</td>
<td>coal gasification</td>
</tr>
<tr>
<td>Alberni Valley</td>
<td>landfill biogas</td>
</tr>
<tr>
<td>Bailey</td>
<td>landfill biogas</td>
</tr>
<tr>
<td>Cache Creek</td>
<td>landfill biogas</td>
</tr>
<tr>
<td>Comox Valley</td>
<td>landfill biogas</td>
</tr>
<tr>
<td>Foothills Blvd</td>
<td>landfill biogas</td>
</tr>
<tr>
<td>Glenmore</td>
<td>landfill biogas</td>
</tr>
<tr>
<td>Greater Vernon</td>
<td>landfill biogas</td>
</tr>
<tr>
<td>Minnie’s Pit</td>
<td>landfill biogas</td>
</tr>
<tr>
<td>MSW2_LM</td>
<td>mass burn incineration</td>
</tr>
<tr>
<td>Mt. Garibaldi</td>
<td>geothermal</td>
</tr>
<tr>
<td>Site C</td>
<td>hydro</td>
</tr>
<tr>
<td>Small Co-generation</td>
<td>combined heat and power</td>
</tr>
<tr>
<td>Wind_PC_21</td>
<td>wind</td>
</tr>
<tr>
<td>Wind_PC13</td>
<td>wind</td>
</tr>
<tr>
<td>Wind_PC19</td>
<td>wind</td>
</tr>
<tr>
<td>Wind_PC28</td>
<td>wind</td>
</tr>
</tbody>
</table>
Thus, British Columbia will still pay $83/MWh, but will recover the cost more slowly and from a different set of its inhabitants. For example, the elimination of water rental means less money for British Columbia’s general revenues and, eventually, higher taxes for taxpayers.

Ironically, the towering edifice of studies is built on a few significant assumptions made largely without justification. Each assumption is controversial. Some differ dramatically from estimates accepted throughout the industry; others are simply arbitrary.

The results of the assumptions are equally arbitrary, since changing the pivotal assumptions shifts the entire analysis. Assumptions concerning the cost of capital and the discount rate, the cost of alternatives, and the cost of fuel effectively determine the result regardless of the scale of the analysis that follows after these assumptions are made:

---

The discount rate lies at the heart of any cost benefit study. In fact, the selection of a discount rate can drastically change the results of the rest of the analysis, overwhelming any other single assumption. The graphic above illustrates the critical importance of the discount rate to the entire edifice that balances upon this one critical assumption. The discussion of this critical component of the analysis in the 2013 IRP can only be described as sketchy and inadequate. The entire presentation on the discount rate is limited to one paragraph:
4.4.3.3 Discount Rate

Discount rates reflect the market demand for, or opportunity cost of, the capital associated with projects of similar risk. This IRP used 5 per cent and 7 per cent discount rates to calculate levelized resource unit costs (UECs and UCCs) for BC Hydro and IPP resources respectively. The updated discount rates reflect the change in BC Hydro’s WACC and the updated assumption of IPP’s WACC. In the long-term planning context, the discount rate methodology is consistent with the WACC used to calculate cost streams of installed resources.8,9

BC Hydro commissioned a review of its methodology on September 23, 2014.10 The review of the discount rate methodology was equally brief:

BC Hydro utilizes two different values for weighted average cost of capital in its Integrated Resource Plan. The Company recommends a 5% real WACC for its own investments and 7% for IPPs and other third party developers; the 2% differential (and a sensitivity that reduces the differential to 1%) is set out in the Site C hydro project environmental assessment documentation and the IRP. The BC Hydro rate of 5% is reasonable, as BC Hydro’s borrowing is guaranteed by the government, and the Company may also borrow directly from the Province. The British Columbia Utilities Commission recognizes this, stating that “With respect to the cost of capital, BC Hydro projects will

9 Utility planning documents often use idiosyncratic acronyms. UEC stands for Unit Energy Cost. UCC stands for Unit Capacity Cost. IRP stands for Integrated Resource Plan. WACC stands for the Weighted Average Cost of Capital.
clearly have an advantage as a result of...access to the Province’s high credit rating.”

Utilities similar to BC Hydro appear to be using comparable values for WACC. In its Needs For and Alternatives To Business Case submission, for example, Manitoba Hydro conducted its resource analysis using a WACC of 5.05% in its base case.¹¹

The kindest thing to be said about the proposed discount rates is that they are not wrong. Unfortunately, they are also not right. Synapse points to a similar number used by Manitoba Hydro. Synapse could easily reference much higher numbers for hydro projects used by Hydro-Quebec and the Bonneville Power Administration.¹²,¹³ Indeed, Bonneville makes an interesting statement in its own discount rate derivation:

Recently, the Ibbotson data was complimented [sic] by a more intensive study performed by BPA Finance staff in which public utilities across North America were surveyed about their discount theory and practice. A few of the utilities that participated were Western Area Power Administration (WAPA), BC Hydro, BC Transmission, Tennessee Valley Authority (TVA), New York Power Authority (NYPA), and Sacramento Municipal Utility District (SMUD).

BPA’s current rates of 12% for Hydro capital investments and 9% for non-replacement Transmission capital investments are reasonable in light of the

¹¹ Ibid., page 2.
¹² Présentation augmentation capacité La Grande, Hydro-Quebec, October 2013, workpapers.
benchmarking study and the benchmarking reinforced BPA’s existing practice of using a risk adjusted discount rate.\textsuperscript{14} (emphasis supplied)

Bonneville Power Administration has cited BC Hydro in defense of adopting a 12% discount rate for hydroelectric projects. Tennessee Valley Authority uses discount rates between 6\% and 12\% based on various factors.\textsuperscript{15} The clear implication is that BC Hydro’s choice of a discount rate might be opportunistically chosen to benefit the selection of Site C in the Integrated Resource Plan, but a different, higher value has been used internally.

While discount rates often sound academic to those who have not been schooled in energy economics, their impact on decision-making is immense. The situation revolves around the timing of investments. Hydroelectric projects require substantial capital investments. Their operating costs are very low. This means that they are relatively unaffected by discount rate assumptions. Thermal plants – especially those fueled by natural gas – have relatively low capital costs, but also relatively high operating costs. Their economic viability is greatly affected by the choice of a discount rate.

When we take the table of the twenty lowest UECs and use a discount rate of 12\% for Site C, while leaving in a 200 basis point higher discount rate for other resources, the order changes dramatically as capital intensive resources are shifted to the right in the chart and those whose major cost is fuel are shifted left.

\textsuperscript{14} Ibid., page 4.
\textsuperscript{15} ENERGY VISION 2020, April 9, 2009, Tennessee Valley Authority, page T8.35.
A follow-up question is why the discount rates used by major utilities are so high for hydroelectric facilities like Site C. If you ask a major utility, you are likely to receive a response similar to BPA:

Risk Premium – This is the measure of the riskiness of the investment. Common elements of risk specific to BPA would be project construction risk, uncertain water and weather risk, and stranded cost risk. Neglecting to consider project risk could lead BPA to select poor investments and put an undue burden on ratepayers.\(^\text{16}\)

\(^{16}\) Ibid., page 3.
When I asked the identical question in negotiations with Hydro-Quebec last year, they replied that the high discount rate represented a substantial dedication of capital to produce a product in a market with dramatic price changes and high volatility.

BC Hydro has assumed that an additional 200 basis point should be added to the discount rate for projects built by independent power producers. This is an interesting hypothesis, although it seems somewhat arbitrary. The least expensive UEC in the chart above is a 500 MW combined cycle gas unit. The units are common choices for utilities. Depending on the utility, they are either purchased from third parties or built by the utility. In recent years, utilities have been building their own resources, so no such additional risk premium is necessary. Eliminating the 200 basis point penalty for non-Site C projects produces the following chart:
Some utilities like Hydro-Quebec even use lower discount rates for wind – even if there is an outside developer. For example, Hydro-Quebec’s wind tariff specifies a discount rate of 3.5%.\(^\text{17}\)

While the discount rate is the pivotal assumption in an analysis of this sort, a variety of other assumptions should be considered as well.

The U.S. Energy Information Administration (EIA) is an excellent source for basic data. A table frequently relied upon in the electric industry is EIA’s summary of the cost of central station generating facilities:

\(^{17}\) Terms of Reference for the Siting of Wind Farms on Farmland and in Woodlands, Hydro-Quebec, November 17, 2013.

In general, the EIA is quite a bit more optimistic on plant costs than BC Hydro’s Resource Operations Database (RODAT).\(^{19}\) For example, a conventional combined cycle gas unit is $869/kW (U.S.) versus the RODAT’s $1,137/kW.\(^{20}\) The standard unit is also significantly more efficient. The EIA has a heat rate of 7,050 btu/kWh versus the RODAT’s 7,362 btu/kWh.

BC Hydro’s pessimism on plant costs is not restricted to thermal units. Wind farm equipment is usually highly standardized. Major manufacturers sell thousands of virtually identical wind turbines throughout North America. The EIA data indicates that wind turbines will cost $1,850/kW for a 100 MW utility scale project. This is consistent with industry experience. The RODAT’s three cheapest wind projects – PC13, PC19, and PC21 – are $2,857/kW (U.S.). Since the underlying equipment is most likely the same, the only explanation would be that wind farms in British Columbia are extremely more remote than those in Washington State and that transportation costs are almost $1,000/kW more. Since these projects are in the Peace River area, this seems unlikely. Correcting the RODAT data using EIA plant assumptions shows the following rankings for the twenty cheapest alternatives:

\(^{19}\) RODAT’s assumptions concerning the 750 MW Integrated Gasification Combined Cycle option are far more optimistic than the EIA’s and do not match industry experience. Substantial doubt exists that this is a viable option under any foreseeable set of assumptions. It has been kept in the chart for comparison purposes only – using RODAT’s low capital cost estimate.

\(^{20}\) The 2013 BC Hydro assumes a long term exchange rate of .9693 U.S. dollars to the Canadian dollar at page 4-63. This value has been used in adjusting RODAT with U.S. financial values.
Again, Site C continues to look like an increasingly expensive choice compared to wind, natural gas, and other alternatives.

Yet another issue is fuel costs. Our ability to forecast fossil fuels is limited. Over the last decade we have gone from a widespread perception that oil and gas were reaching “peak” levels. This Malthusian view has fallen victim to technological change. In reality, production is up and prices have fallen. Recently the highly respected bond rating firm, Moody’s, has predicted that world natural gas prices have fallen so low that LNG export terminals in Canada and the U.S. are increasingly unlikely.  

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21 Global supply glut threatens British Columbia's LNG projects, Brent Jang, Globe and Mail, April 7, 2015.
While the change in technology has confounded forecasters, it is still logical to compare the forecast to real markets. Natural gas has robust forward markets on a variety of exchanges. The following chart compares the forecasts in the 2013 Integrated Resource Plan with today’s NYMEX forward prices:

![Site C IRP Natural Gas Forecast with Nymex Forward Prices](image)

The thick blue line represents current quotes on the NYMEX. Scenario 1 represents the natural gas price BC Hydro has modelled in the RODAT. The actual price is considerably lower and is available for purchase through 2025.22

This adjustment should also be made to the RODAT data. The cumulative set of adjustments is telling:

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22 NYMEX prices have been adjusted to Canadian dollars using the assumption contained in the 2013 Integrated Resource Plan. Real price escalation after 2025 is assumed to continue at the 2020 to 2025 rate.
In summary, adopting realistic changes from standard and well respected sources makes an enormous difference. Using BC Hydro’s assumptions, the difference in cost between the least expensive option and Site C is minimized. Using industry standard assumptions, Site C is more than three times as costly as the least expensive option. In fact, Site C fares poorly when compared to cogeneration, wind, landfill, and coal gasification.
While the cost and choice of options deserve further analysis, the simple conclusion is that Site C is more expensive – dramatically so – than the renewable/natural gas portfolios elsewhere in the U.S. and Canada. Our analysis indicates that the Site C portfolio may well be twice as costly as the renewable/natural gas portfolio adopted elsewhere.

<table>
<thead>
<tr>
<th>Type of Plant</th>
<th>Average $/MWh</th>
</tr>
</thead>
<tbody>
<tr>
<td>Natural gas</td>
<td>$58.04</td>
</tr>
<tr>
<td>Combined Heat &amp; Power</td>
<td>$73.33</td>
</tr>
<tr>
<td>Wind</td>
<td>$74.36</td>
</tr>
<tr>
<td>Landfill biogas</td>
<td>$85.50</td>
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<tr>
<td>Coal gasification</td>
<td>$99.97</td>
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<tr>
<td>Geothermal</td>
<td>$112.30</td>
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<tr>
<td>Hydro</td>
<td>$164.35</td>
</tr>
<tr>
<td>Mass Burn incineration</td>
<td>$256.85</td>
</tr>
</tbody>
</table>
Robert McCullough – Curriculum Vitae
Principal
McCullough Research, 3816 S.E. Woodstock Place, Portland, OR 97202 USA

Professional Experience

1985-present
Principal, McCullough Research: provide strategic planning assistance, litigation support, and planning for a variety of customers in energy, regulation, and primary metals

1996-present
Adjunct Professor, Economics, Portland State University

1990-1991
Director of Special Projects and Assistant to the Chairman of the Board, Portland General Corporation: conducted special assignments for the Chairman in the areas of power supply, regulation, and strategic planning

1988-1990
Vice President in Portland General Corporation’s bulk power marketing utility subsidiary, Portland General Exchange: primary negotiator on the purchase of 550 MW transmission and capacity package from Bonneville Power Administration; primary negotiator of PGX/M, PGC’s joint venture to establish a bulk power marketing entity in the Midwest; negotiated power contracts for both supply and sales; coordinated research function

1987-1988
Manager of Financial Analysis, Portland General Corporation: responsible for M&A analysis, restructuring planning, and research support for the financial function; reported directly to the CEO on the establishment of Portland General Exchange; team member of PGC’s acquisitions task force; coordinated PGC’s strategic planning process; transferred to the officer’s merit program as a critical corporate manager

1981-1987
created BPA’s innovative aluminum tariffs (adopted by BPA in 1986); led PGC activities, reporting directly to the CEO and CFO on a number of special activities, including litigation and negotiations concerning WPPSS, the Northwest Regional Planning Council, various electoral initiatives, and the development of specific tariffs for major industrial customers; member of the Washington Governor’s Task Force on the Vancouver Smelter (1987) and the Washington Governor’s Task Force on WPPSS Refinancing (1985); member of the Oregon Governor’s Work Group On Extra-Regional Sales (1983); member of the Advisory Committee to the Northwest Regional Planning Council (1981)

1979-1980

Economist, Rates and Revenues Department, Portland General Electric: responsible for financial and economic testimony in the 1980 general case; coordinated testimony in support of the creation of the DRPA (Domestic and Rural Power Authority) and was a witness in opposition to the creation of the Columbia Public Utility District in state court; member of the Scientific and Advisory Committee to the Northwest Regional Power Planning Council

Economic Consulting

2014-2015  Market analysis of the NYISO for the New York State Assembly

2014  Advisor to the Grand Council of the Cree on uranium mining in Quebec

2014  Support for the investigation of Barclays Bank

2013  Advisor to Environmental Defense Fund on gasoline and oil issues in California

2013  Advisor to Energy Foundation on Ohio competitive issues

2013  Export market review in the Maritime Link proceeding

2013  Retained to do a business case analysis of the Columbia Generating Station by the Physicians for Social Responsibility

2011  Consultant to Citizens Action Coalition of Indiana on Indiana Gasification LLC project

2010-present  Analysis and expert witness testimony for Block Island Intervenors concerning Deepwater offshore wind project
<table>
<thead>
<tr>
<th>Year(s)</th>
<th>Activity Description</th>
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<tbody>
<tr>
<td>2010</td>
<td>Analysis for Eastern Environmental Law Center of 25 closed cycle plants in New York State</td>
</tr>
<tr>
<td>2010</td>
<td>Advisor on BPA transmission line right of way issues</td>
</tr>
<tr>
<td>2009-2010</td>
<td>Advisor to Gamesa USA on a marketing plan to promote a wind farm in the Pacific Northwest</td>
</tr>
<tr>
<td>2009-2010</td>
<td>Expert witness in City of Alexandria vs. Cleco</td>
</tr>
<tr>
<td>2009-present</td>
<td>Expert witness in City of Beaumont v. Entergy</td>
</tr>
<tr>
<td>2008-2009</td>
<td>Consultant to AARP Connecticut and Texas chapters on the need for a state power authority (Connecticut) and balancing energy services (Texas)</td>
</tr>
<tr>
<td>2008-present</td>
<td>Advisor to the American Public Power Association on administered markets</td>
</tr>
<tr>
<td>2008</td>
<td>Expert witness on trading and derivative issues in Barrick Gold litigation</td>
</tr>
<tr>
<td>2008-present</td>
<td>Advisor to Jackson family in Pelton/Round Butte dispute</td>
</tr>
<tr>
<td>2006-present</td>
<td>Advisor to the Illinois Attorney General on electric restructuring issues</td>
</tr>
<tr>
<td>2006-present</td>
<td>Expert witness for Lloyd’s of London in SECLP insurance litigation</td>
</tr>
<tr>
<td>2006-2007</td>
<td>Advisor to the City of Portland in the investigation of Portland General Electric</td>
</tr>
<tr>
<td>2005-2006</td>
<td>Expert witness for Antara Resources in Enron litigation</td>
</tr>
<tr>
<td>2005-2006</td>
<td>Advisor to Utility Choice Electric</td>
</tr>
<tr>
<td>2005-2007</td>
<td>Expert witness for Federated Rural Electric Insurance Company and TIG Insurance in Cowlitz insurance litigation</td>
</tr>
<tr>
<td>2005-2007</td>
<td>Advisor to Gray’s Harbor PUD on market manipulation</td>
</tr>
<tr>
<td>2005-2007</td>
<td>Advisor to the Montana Attorney General on market manipulation</td>
</tr>
<tr>
<td>2004-2005</td>
<td>Expert witness for Factory Mutual in Northwest Aluminum litigation</td>
</tr>
</tbody>
</table>
2004  Advisor to the Oregon Department of Justice on market manipulation

2003-2006  Expert witness for Texas Commercial Energy

2003-2004  Advisor to The Energy Authority

2002-2005  Advisor to the U.S. Department of Justice on market manipulation issues

2002-2004  Expert witness for Alcan in Powerex arbitration


2002-2003  Expert witness for Stanislaus Food Products

2002  Advisor to VHA Pennsylvania on power purchasing

2002  Expert witness for Sierra Pacific in Enron litigation

2002-2004  Advisor to U.S. Department of Justice

2002-2007  Expert witness for Snohomish PUD in Enron litigation

2002-1010  Expert witness for Snohomish in Morgan Stanley investigation

2001-2005  Advisor to Nordstrom

2001-2005  Advisor to Steelscape Steel on power issues in Washington and California

2001-2008  Advisor to VHA Southwest on power purchasing

2001-present  Expert witness for City of Seattle, Seattle City Light and City of Tacoma in FERC’s EL01-10 refund proceeding

2001  Advisor to California Steel on power purchasing

2001  Advisor to the California Attorney General on market manipulations in the Western Systems Coordinating Council power markets

2000-present  Expert witness for Wah Chang in PacifiCorp litigation
2000-2001 Expert witness for Southern California Edison in Bonneville Power Administration litigation

2000-2001 Advisor to Blue Heron Paper on West Coast price spikes

2000 Expert witness for Georgia Pacific and Bellingham Cold Storage in the Washington Utilities and Transportation Commission’s proceeding on power costs

1999 Expert report for the Center Helios on Freedom of Information in Québec

1999-2002 Advisor to Bayou Steel on alternative energy resources

1999-2000 Expert witness for the Large Customer Group in PacifiCorp’s general rate case

1999-2000 Expert witness for Tacoma Utilities in WAPA litigation

1999-2000 Advisor for Nucor Steel and Geneva Steel on PacifiCorp’s power costs

1999-2000 Advisor to Abitibi-Consolidated on energy supply issues

1999 Advisor to GTE regarding Internet access in competitive telecommunication markets

1999 Advisor to Logansport Municipal Utilities

1998-2001 Advisor to Edmonton Power on utility plant divestiture in Alberta

1998-2001 Energy advisor for Boise Cascade

1998-2000 Advisor to California Steel on power purchasing

1998-2000 Advisor to Nucor Steel on power purchasing and transmission negotiations

1998-2000 Advisor to Cominco Metals on the sale of hydroelectric dams in British Columbia

1998-2000 Advisor to the Betsiamites on the purchase of hydroelectric dams in Québec

1998-1999 Advisor to the Illinois Chamber of Commerce concerning the affiliate electric and gas program
1998 Intervention in Québec’s first regulatory proceeding on behalf of the Grand Council of the Cree

1998 Market forecasts for Montana Power’s restructuring proceeding

1997-1999 Advisor to the Columbia River Intertribal Fish Commission on Columbia fish and wildlife issues

1997-1998 Advisor to Port of Morrow regarding power marketing with respect to existing gas turbine plant

1997-1998 Expert witness for Tenaska in BPA litigation

1997 Advisor to Kansai Electric on restructuring in the electric power industry (with emphasis on the California markets)

1997-2004 Expert witness for Alcan in BC Hydro litigation

1996-1997 Bulk power purchasing for the Association of Bay Area Cities

1996-1997 Advisor to Texas Utilities on industrial issues

1996-1997 Expert witness for March Point Cogeneration in Puget Sound Power and Light litigation

1996 Advisor to Longview Fibre on contract issues

1995-present Bulk power supplier for several Pacific Northwest industrials

1995-1997 Advisor to Tacoma Utilities on contract issues

1995-1999 Advisor to Seattle City Light on industrial contract issues

1995-1996 Expert witness for Tacoma Utilities in WAPA litigation

1994-1995 Advisor to Idaho Power on Southwest Intertie Project marketing

1993-2001 Northwest representative for Edmonton Power

1993-1997 Expert witness for MagCorp in PacifiCorp litigation

1992-1995 Advisor to Citizens Energy Corporation

1992-1994 Negotiator on proposed Bonneville Power Administration aluminum contracts
<table>
<thead>
<tr>
<th>Year(s)</th>
<th>Description</th>
</tr>
</thead>
<tbody>
<tr>
<td>1981-1989</td>
<td>Consulting projects including: financial advice for the Oregon AFL-CIO; statistical analysis of equal opportunity for Oregon Bank; cost of capital for the James River dioxin review; and economic analysis of qualifying facilities for Washington Hydro Associates</td>
</tr>
<tr>
<td>1980-1986</td>
<td>Taught classes in senior and graduate forecasting, micro-economics, and energy at Portland State University</td>
</tr>
<tr>
<td>1987-1988</td>
<td>Created the variable aluminum tariff for Big Rivers Electric Corporation: responsibilities included testimony before the Kentucky Public Service Commission and negotiations with BREC’s customers (the innovative variable tariff was adopted by the Commission in August 1987); supported negotiations with the REA in support of BREC’s bailout debt restructuring</td>
</tr>
<tr>
<td>1988</td>
<td>Facilitated the settlement of Commonwealth Edison’s 1987 general rate case and restructuring proposal for the Illinois Commerce Commission; reported directly to the Executive Director of the Commission; responsibilities included financial advice to the Commission and negotiations with Commonwealth and interveners</td>
</tr>
<tr>
<td>1990-1991</td>
<td>Advised the Chairman of the Illinois Commerce Commission on issues pertaining to the 1990 General Commonwealth Rate Proceeding; prepared an extensive analysis of the bulk power marketing prospects for Commonwealth in ECAR and MAIN</td>
</tr>
<tr>
<td>1991</td>
<td>Advisor to Shasta Dam PUD on the California Oregon Transmission Project and related issues</td>
</tr>
<tr>
<td>1991-1992</td>
<td>Financial advisor on the Trojan owners’ negotiation team</td>
</tr>
<tr>
<td>1991-1993</td>
<td>Chairman of the Investor Owned Utilities’ (ICP) committee on BPA financial reform</td>
</tr>
<tr>
<td>1991-2000</td>
<td>Strategic advisor to the Chairman of the Board, Portland General Corporation</td>
</tr>
<tr>
<td>1997-2003</td>
<td>Advisor to the Manitoba Cree on energy issues in Manitoba, Minnesota and Québec; Advisor to the Grand Council of the Cree on hydroelectric development</td>
</tr>
<tr>
<td>1992</td>
<td>Bulk power marketing advisor to Public Service of Indiana</td>
</tr>
<tr>
<td>1990-1991</td>
<td>Advised the Chairman of the Illinois Commerce Commission on issues pertaining to the 1990 General Commonwealth Rate Proceeding; prepared an extensive analysis of the bulk power marketing prospects for Commonwealth in ECAR and MAIN</td>
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<td>1988</td>
<td>Facilitated the settlement of Commonwealth Edison’s 1987 general rate case and restructuring proposal for the Illinois Commerce Commission; reported directly to the Executive Director of the Commission; responsibilities included financial advice to the Commission and negotiations with Commonwealth and interveners</td>
</tr>
</tbody>
</table>
Education

Unfinished Ph.D.  Economics, Cornell University; Teaching Assistant in micro- and macro-economics

M.A.  Economics, Portland State University, 1975; Research Assistant

B.A.  Economics, Reed College, 1972; undergraduate thesis, “Eurodollar Credit Creation”

Areas of specialization include micro-economics, statistics, and finance

Papers and Publications

December 2014  “Nuclear Winter”, *Electricity Policy*

July 2013  “Mid-Columbia Spot Markets and the Renewable Portfolio Standard”, *Public Utilities Fortnightly*

April 14, 2013  “Selling Low and Buying High”, *The Oregonian*

December 2012  “Are Electric Vehicles Actually Cost-Effective?”, *Electricity Policy*

November 30, 2012  “Portland’s Energy Credits: The trouble with buying ‘green’”, *The Oregonian*

July 2009  “Fingerprinting the Invisible Hand”, *Public Utilities Fortnightly*

February 2008  Co-author, “The High Cost of Restructuring”, *Public Utilities Fortnightly*

March 27, 2006  Co-author, “A Decisive Time for LNG”, *The Daily Astorian*

February 9, 2006  “Opening the Books”, *The Oregonian*

August 2005  “Squeezing Scarcity from Abundance”, *Public Utilities Fortnightly*

April 1, 2002  “The California Crisis: One Year Later”, *Public Utilities Fortnightly*

March 13, 2002  “A Sudden Squall”, *The Seattle Times*

March 1, 2002  “What the ISO Data Says About the Energy Crisis”, *Energy User News*
February 1, 2001  “What Oregon Should Know About the ISO”, Public Utilities Fortnightly


March 1999  “Winners & Losers in California”, Public Utilities Fortnightly

July 15, 1998  “Are Customers Necessary?”, Public Utilities Fortnightly

March 15, 1998  “Can Electricity Markets Work Without Capacity Prices?”, Public Utilities Fortnightly

February 1998  “Coping With Interruptibility”, Energy Buyer

January 1998  “Pondering the Power Exchange”, Energy Buyer


November 1997  “Is Capacity Dead?”, Energy Buyer

October 1997  “Pacific Northwest: An Overview”, Energy Buyer

August 1997  “A Primer on Price Volatility”, Energy Buyer

June 1997  “A Revisionist’s History of the Future”, Energy Buyer

Winter 1996  “What Are We Waiting for?” Megawatt Markets


McCullough Research Reports

January 2, 2015  “Data and Methodological Errors in the Portland Commercial Street Fee”


December 11, 2013  “Economic Analysis of the Columbia Generating Station”

February 21, 2013  “McCullough Research Rebuttal to Western States Petroleum Association”
November 15, 2012  “May and October 2012 Gasoline Price Spikes on the West Coast”
June 5, 2012  “Analysis of West Coast Gasoline Prices”
October 3, 2011  “Lowering Florida’s Electricity Prices”
July 14, 2011  “2011 ERCOT Blackouts and Emergencies”
March 1, 2010  “Translation” of the September 29, 2008 NY Risk Consultant’s Hydraulics Report to Manitoba Hydro CEO Bob Brennan
December 2, 2009  “Review of the ICF Report on Manitoba Hydro Export Sales”
June 5, 2009  “New York State Electricity Plants’ Profitability Results”
May 5, 2009  “Transparency in ERCOT: A No-cost Strategy to Reduce Electricity Prices in Texas”
April 7, 2009  “A Forensic Analysis of Pickens’ Peak: Speculation, Fundamentals or Market Structure”
March 30, 2009  “New Yorkers Lost $2.2 Billion Because of NYISO Practices”
February 24, 2009  “The Need for a Connecticut Power Authority”
January 7, 2009  “Review of the ERCOT December 18, 2008 Nodal Cost Benefit Study”
August 6, 2008  “Seeking the Causes of the July 3rd Spike in World Oil Prices” (updated September 16, 2008)
April 7, 2008  “Kaye Scholer’s Redacted ‘Analysis of Possible Complaints Relating to Maryland’s SOS Auctions’”
February 1, 2008  “Some Observations on Societe Generale’s Risk Controls”
June 26, 2007  “Looking for the ‘Voom’: A Rebuttal to Dr. Hogan’s ‘Acting in Time: Regulating Wholesale Electricity Markets’”
September 26, 2006  “Did Amaranth Advisors, LLC Attempt to Corner the March 2007 NYMEX at Henry Hub?”


April 12, 2005  “When Oil Prices Rise, Using More Ethanol Helps Save Money at the Gas Pump”

April 12, 2005  “When Farmers Outperform Sheiks: Why Adding Ethanol to the U.S. Fuel Mix Makes Sense in a $50-Plus/Barrel Oil Market”

April 12, 2005  “Enron’s Per Se Anti-Trust Activities in New York”

February 15, 2005  “Employment Impacts of Shifting BPA to Market Pricing”

June 28, 2004  “Reading Enron’s Scheme Accounting Materials”

June 5, 2004  “ERCOT BES Event”

August 14, 2003  “Fat Boy Report”

May 16, 2003  “CERA Decision Brief”

January 16, 2003  “California Electricity Price Spikes”


August 17, 2002  “Three Days of Crisis at the California ISO”

July 9, 2002  “Market Efficiencies”

June 26, 2002  “Senate Fact Sheet”

June 5, 2002  “Congestion Manipulation”

May 5, 2002  “Enron’s Workout Plan”

March 31, 2002  “A History of IJM2”

February 2, 2002  “Understanding IJM”

January 22, 2002  “Understanding Whitewing”
<table>
<thead>
<tr>
<th>Date</th>
<th>Event</th>
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<tbody>
<tr>
<td>December 15, 2014</td>
<td>Testimony before the Bureau d’audiences publiques sur l’environnement (BAPE) in Quebec, “Uranium Mining in Quebec: Four Conclusions”</td>
</tr>
<tr>
<td>November 15, 2012</td>
<td>Testimony before the California State Senate Select Committee on Bay Area Transportation on West Coast gasoline price spikes in 2012</td>
</tr>
<tr>
<td>July 20, 2010</td>
<td>Testimony before the Rhode Island Public Utility Commission on the Deepwater offshore wind project</td>
</tr>
<tr>
<td>April 7, 2009</td>
<td>Testimony before the U.S. Senate Committee on Energy and Natural Resources on “Pickens’ Peak”</td>
</tr>
<tr>
<td>February 24, 2009</td>
<td>Testimony before the Energy and Technology Committee, Connecticut General Assembly, “An Act Establishing a Public Power Authority” on behalf of AARP</td>
</tr>
<tr>
<td>September 16, 2008</td>
<td>Testimony before the U.S. Senate Committee on Energy and Natural Resources, “Depending On 19th Century Regulatory Institutions to Handle 21st Century Markets”</td>
</tr>
<tr>
<td>January 7, 2008</td>
<td>Supplemental Comment (“The Missing Benchmark in Electricity Deregulation”) before the Federal Energy Regulatory Commission on behalf of American Public Power Association, Docket Nos. RM07-19-000 and AD07-7-000</td>
</tr>
<tr>
<td>August 7-8, 2007</td>
<td>Testimony before the Oregon Public Utility Commission on behalf of Wah Chang, Salem, Oregon, Docket No. UM 1002</td>
</tr>
<tr>
<td>February 23 and 26, 2007</td>
<td>Testimony before the Federal Energy Regulatory Commission on behalf of Public Utility District No. 1 of Snohomish County, Washington, Docket No. EL03-180</td>
</tr>
<tr>
<td>October 2, 2006</td>
<td>Direct Testimony before the Régie de l’énergie, Gouvernement du Québec on behalf of the Grand Council of the Cree</td>
</tr>
</tbody>
</table>


December 15, 2005  Direct Testimony before the Public Utility Commission of the State of Oregon on behalf of Wah Chang, Wah Chang v. PacifiCorp in Docket UM 1002

December 14, 2005  Deposition before the United States District Court Western District of Washington at Tacoma on behalf of Federated Rural Electric Insurance Exchange and TIG Insurance Company, Federated Rural Electric Insurance Exchange and TIG Insurance Company v. Public Utility District No. 1 of Cowlitz County, No. 04-5052RBL

December 4, 2005  Expert Report on behalf of Utility Choice Electric in Civil Action No. 4:05-CV-00573


May 1, 2005  Rebuttal Expert Report on behalf of Factory Mutual, Factory Mutual v. Northwest Aluminum


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<tr>
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<tbody>
<tr>
<td>April 10, 2004</td>
<td>Rebuttal Testimony on behalf of the Office of City and County Attorneys, San Francisco, California, City and County Attorneys, San Francisco, California v. Turlock Irrigation District, Non-Binding Arbitration</td>
</tr>
<tr>
<td>February 27, 2003</td>
<td>Direct Testimony before the Federal Energy Regulatory Commission on behalf of the City of Tacoma, Washington and the Port of Seattle, Washington, Docket No. EL01-10-005</td>
</tr>
<tr>
<td>October 7, 2002</td>
<td>Rebuttal Testimony before the Federal Energy Regulatory Commission on behalf of Public Utility District No. 1 of Snohomish County, Washington, Docket No. EL02-26, et al.</td>
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<td>October 2002</td>
<td>Expert Report before the Circuit Court of the State of Oregon for the County of Multnomah on behalf of Alcan, Inc., Alcan, Inc. v. Powerex Corp., Case No. 50 198 T161 02</td>
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August 8, 2002  Deposition by Morgan Stanley Capital Group, Inc. before the Federal Energy Regulatory Commission on behalf of Public Utility District No. 1 of Snohomish County, Washington, Docket No. EL02-26, et al.

June 28, 2002  Direct Testimony before the Federal Energy Regulatory Commission on behalf of the City of Tacoma, Washington, Docket No. EL02-26, et al.


May 6, 2002  Rebuttal Testimony before the Public Service Commission of Utah on behalf of Magnesium Corporation of America in the Matter of the Petition of Magnesium Corporation of America to Require PacifiCorp to Purchase Power from MagCorp and to Establish Avoided Cost Rates, Docket No. 02-035-02

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August 30, 2001  Rebuttal Testimony before the Federal Energy Regulatory Commission on behalf of Seattle City Light, Docket No. EL01-10
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<td>June 12, 2001</td>
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<td>April 17, 2001</td>
<td>Before the Public Utility Commission of the State of Oregon, Direct Testimony on behalf of Wah Chang, Wah Chang v. PacifiCorp in Docket UM 1002</td>
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<td>March 17, 2000</td>
<td>Rebuttal Testimony before the Public Service Commission of Utah on behalf of the Large Customer Group in the Matter of the Application of PacifiCorp for Approval of Its Proposed Electric Rate Schedules and Electric Service Regulations, Docket No. 99-035-10</td>
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<td>February 1, 2000</td>
<td>Direct Testimony before the Public Service Commission of Utah on behalf of the Large Customer Group in the Matter of the Application of PacifiCorp for Approval of Its Proposed Electric Rate Schedules and Electric Service Regulations, Docket No. 99-035-10</td>
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**Presentations**

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<td>May 6, 2014</td>
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<td>April 30, 2014</td>
<td>“Economic Analysis of the Columbia Generating Station”, Portland State University, Portland, Oregon</td>
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<td>April 22, 2014</td>
<td>“Economic Analysis of the Columbia Generating Station”, Clark County, Vancouver, Washington</td>
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<td>January 1, 2014</td>
<td>“Economic Analysis of the Columbia Generating Station”, Bonneville Power Administration, Portland, Oregon</td>
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December 1, 2013  “Peak Peddling: Has Portland Bicycling Reached the Top of the Logistic Curve?” Oregon Transportation Research and Education Consortium, Portland, Oregon

July 12, 2013  “Economic Analysis of the Columbia Generating Station”, Tacoma, Washington


October 14, 2009  “Do ISO Bidding Processes Result in Just and Reasonable Rates?”, legal seminar, American Public Power Association, Savannah, Georgia

June 22, 2009  “Pickens’ Peak Redux: Fundamentals, Speculation, or Market Structure”, International Association for Energy Economics

June 5, 2009  “Transparency in ERCOT: A No-cost Strategy to Reduce Electricity Prices in Texas”, Presentation at Texas Legislature

May 8, 2009  “Pickens’ Peak”, Economics Department, Portland State University

April 7, 2009  “Pickens’ Peak: Speculators, Fundamentals, or Market Structure”, 2009 EIA energy conference, Washington, DC

February 4, 2009  “Why We Need a Connecticut Power Authority”, presentation to the Energy and Technology Committee, Connecticut General Assembly

October 28, 2008  “The Impact of a Volatile Economy on Energy Markets”, NAESCO annual meeting, Santa Monica, California


May 23, 2007  “Past Efforts and Future Prospects for Electricity Industry Restructuring: Why Is Competition So Expensive?”, Portland State University

May 18, 2006  “Developing a Power Purchase/Fuel Supply Portfolio”

February 12, 2005  “Northwest Job Impacts of BPA Market Rates”

January 5, 2005  “Why Has the Enron Crisis Taken So Long To Solve?”, Public Power Council, Portland, Oregon

September 20, 2004  “Project Stanley and the Texas Market”, Gulf Coast Energy Association, Austin, Texas


June 8, 2004  “Caveat Emptor”, ELCON West Coast Meeting, Oakland, California

June 9, 2004  “Enron Discovery in EL03-137/180”

March 31, 2004  “Governance and Performance”, Public Power Council, Portland, Oregon


September 17, 2002  “Three Crisis Days”, California Senate Select Committee, Sacramento, California

June 10, 2002  “Enron Schemes”, California Senate Select Committee Sacramento, California

May 2, 2002  “One Hundred Years of Solitude”

March 21, 2002  “Enron’s International Ventures”, Oregon Bar International Law Committee, Portland, Oregon

March 19, 2002  “Coordinating West Coast Power Markets”, GasMart, Reno, Nevada
March 19, 2002  “Sauron’s Ring”, GasMart, Reno, Nevada
November 12, 2001  “Artifice or Reality”, EPIS Energy Forecast Symposium, Skamania, Washington
October 24, 2001  “The Case of the Missing Crisis” Kennewick Rotary Club, Kennewick, Washington
August 18, 2001  “Preparing for the Next Decade”
June 26, 2001  “Examining the Outlook on Deregulation”
June 25, 2001  Presentation, Energy Purchasing Institute for International Research (IIR), Dallas, Texas
May 24, 2001  “Five Years”
May 10, 2001  “A Year in Purgatory”, Utah Industrial Customers Symposium-Utah Association of Energy Users, Salt Lake City, Utah
May 1, 2001  “What to Expect in the Western Power Markets this Summer”, Western Power Market Seminar, Denver, Colorado
April 23, 2001  “Emerging Markets for Natural Gas”, West Coast Gas Conference, Portland, Oregon
April 4, 2001  “Perfect Storm”, Regulatory Accounting Conference, Las Vegas, Nevada
February 21, 2001  “Future Imperfect”, Pacific Northwest Steel Association, Portland, Oregon


February 6, 2001  Presentation, Boise Cascade Management, Boise, Idaho


October 26, 2000  “Tsunami: Market Prices since May 22nd”, International Association of Refrigerated Warehouses, Los Vegas, California

October 11, 2000  “Tsunami: Market Prices since May 22nd”, Price Spikes Symposium, Portland, Oregon


June 5, 2000  “Northwest Market Power”, Georgia Pacific Management

May 10, 2000  “Magnesium Corporation Developments”, Utah Public Utilities Commission


January 12, 2000  “Northwest Reliability Issues”, Oregon Public Utility Commission

Volunteer Positions

2013-Present  Eastmoreland Neighborhood Association, President

2013-Present  Southeast Uplift, Chair
Geothermal Energy: The Renewable and Cost Effective Alternative to Site C

An Assessment of the True Value of Geothermal Energy

November 2014      Canadian Geothermal Energy Association
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Geothermal Energy:
The Renewable and Cost-Effective Alternative to Site C
An Assessment of the True Value of Geothermal Energy

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Context

During the Joint Review Panel of the Site C Clean Energy Project (JRP) hearings, the Canadian Geothermal Energy Association (CanGEA) was granted Interested Party status. Partially as a result of CanGEA’s assertions, the JRP eventually concluded that BC Hydro’s lack of research on geothermal energy had:

“left BC Hydro without information about a resource that BC Hydro thinks may offer up to 700 megawatts of firm economic power with low environmental costs.”

While this ruling was encouraging for the status of geothermal energy in Canada, the figure of 700 MW was believed by CanGEA to be considerably low. However, CanGEA had not yet completed the interpretation of field data pertaining to geothermal energy potential, done to global standards, for presentation to the JRP.

CanGEA had also not had an opportunity to complete its review of the economic, socio-economic and environmental benefits of geothermal compared to the proposed Site C Dam project (Site C).

This report closes the information and analysis gap on geothermal power generation in British Columbia.
“a failure to pursue research over the last 30 years into B.C.’s geothermal resources has left BC Hydro without information about a resource that BC Hydro thinks may offer up to 700 megawatts of firm, economic power with low environmental costs.”
– Site C Joint Review Panel

Executive Summary

10 Advantages of Geothermal Energy Not Considered by BC Hydro or the Joint Review Panel:

Now that initial research work is completed, CanGEA is in a position to identify 10 Points Towards Assessing the True Value of Geothermal Energy.

While the province possesses substantial potential, due to the lack of a functioning geothermal industry in the country as a whole, knowledge pertaining to the proper assessment of the value of these potential resources is lacking. During the Joint Review Panel hearings, BC Hydro based their cost estimates pertaining to geothermal projects on their Resource Options Data (RODAT).1 RODAT was, in part, derived from an extra-jurisdictional literature review and then discounted to consider limitations perceived by BC Hydro. Appendix D displays this data. Accordingly, the RODAT geothermal cost estimates were not based on British Columbia data, nor were the subject of independent verification.

CanGEA has found there to be the following advantages to geothermal power projects, which had either not been addressed, or were not adequately quantified during the Joint Review Panel hearings. A majority of these were economic considerations:

1. Geothermal Power Has a Lower UEC and Capital Cost
2. Geothermal Heat is a Valuable By-Product
3. More Permanent Jobs are Generated by Geothermal Operations Than Other Alternatives
4. Costly BC Hydro System Transmission Upgrades are Avoided or Minimized
5. The Power Grid is Strengthened Through Ancillary Services, Including Geothermal Energy’s Unique Base Load and Dispatchable Capacity
6. Geothermal Fluids Create Strategically Significant Mineral and Rare Earth Elements Recovery Opportunities
7. Geothermal Power Plants Can be Built to Meet Demand and Manage or Reduce the Risk of Cost Overruns Associated with Large-Scale Projects

CanGEA also found there to be the following socio-economic and environmental considerations that had not been quantified by BC Hydro:

8. Geothermal Offers Increased Food Security and Price Stability  
9. The Physical and Environmental Footprint of Geothermal is Small  
10. Geothermal Offers a Means to “Green” Oil & Gas and Mining Operations

A summary of these follows:

1) **Geothermal Power Has a Lower UEC and Capital Cost**

The Unit Energy Cost (UEC) for the bundle of geothermal energy projects that BC Hydro selected was $127/MWh. CanGEA is confident based on the analysis presented in this report that there are far more economically viable alternatives elsewhere in the province. The inclusion of these presently “out of the market” geothermal projects needlessly inflates the overall UEC of the geothermal project portfolio. Furthermore, CanGEA questions some of the underlying assumptions in the RODAT. For instance, the plant life and the capacity factor for geothermal power plants, both flash and binary, was found to be too low.

Therefore, these assumptions were adjusted to reflect expected operating conditions in BC, and to recognize the true long lasting and dependable capacity of geothermal power plants. Taking these considerations into account resulted in CanGEA selecting a number of likely baskets of geothermal power project opportunities in the province, which are significantly different than the ones that BC Hydro presented to the JRP. This revision of the project portfolio allowed for updated UECs to be calculated.

This updated information produced new values for plant operating life, availability and capacity factors. It also gave capital costs and operating costs for binary plants. For the flash plant portfolio, RODAT capital and operating costs were retained, although these, too, need further investigation.

In addition to the 5 flash and 8 binary projects from the original RODAT set, a series of new binary projects that had not previously been considered were also added to the portfolio. These additional projects have since come to light as a result of the extensive data gathering, resource estimating and favourability mapping conducted by CanGEA over the past two years, and have been vetted through our CanGEA developer members. The review was also performed by engineering consultants and a global expert (Qualified Person) in resource estimation.

There are a great many potential sites for HSA projects in the sedimentary basins of BC, and they have easy access plus extensive current data on the HSA geothermal potential that is coincident with the oil and gas
development in the region. However, for comparative purposes, the chart includes only one site at 11 MW and several sites at 15 MW.

The graph shows very clearly that using the updated data, BC’s geothermal potential has an enormous potential to supply the province’s electricity needs, at a cost that is very competitive with any other source, including Site C.

The 14 updated binary plants charted have the potential to supply 2,300 GWh/yr at costs under $81/MWh, and there are many more such plants possible given the geothermal power potential in the northeast area of BC, as well as spread around the remainder of the province.

The 5 updated flash plant sites that have already been identified, have the potential to supply another 4,200 GWh/yr, at costs of $80 to $90/MWh, and there are many other potential sites spread around the province as well. It’s a matter of government (and the Crown utility) having the will to drive that development forward.

CanGEA’s preferred portfolio, however, based on our research, shows that there are other possible geothermal projects that are useful for the purposes of comparison to the Site C project. Using only binary plants, which includes the 8 conventional binary plants from the RODAT with 28 HSA plants, 5,100 GWh/yr could be generated at an average cost of only $73/MWh, and a total capital expenditure (CapEx) of only $3.3 billion. Notably, this portfolio would be $10 less costly than the RODAT Site C estimate of $83/MWh. Furthermore, it would be less than half as costly, given Site C’s CapEx is stated at $7.9 billion.
Site C will inevitably have a high transmission cost, while the strategic dispersion of geothermal projects will be able to minimize transmission costs. Thus, there is every reason to believe that given the thoughtful and methodological development of BC's geothermal potential, geothermal power could provide all of BC's future power requirements at a lower cost to ratepayers than the proposed Site C project.

The HSA binary plants could be located in any of BC's sedimentary basins. In the northeast, they could be located adjacent to gas development and production, to facilitate direct electrification much more quickly than by the building of long and expensive transmission lines. In central or southeast BC, they could be located to provide clean, reliable, base load power and ancillary services directly to the BC electricity grid.

2) Geothermal Heat is a Valuable By-Product

Geothermal resources offer a low-cost source of heat that can be utilized in addition to, or independent of power production. Geothermal energy can be used for nearly any commercial or industrial process requiring heat. Such resources are used in 73 countries around the world to spur

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economic growth, and are especially suited to rural areas, Aboriginal communities, and entrepreneurs.

3) More Permanent Jobs are Generated by Geothermal Operations Than Other Alternatives

1,100 MW of geothermal power projects would create much more sustainable employment for surrounding communities. While Site C promises only 160 permanent jobs, U.S. Department of Energy (DOE) statistics indicate that the equivalent amount of geothermal energy would produce 1,870 permanent jobs. This total does not include jobs that result from the direct use of geothermal heat, which are also significant.

4) Costly BC Hydro System Transmission Upgrades are Avoided or Minimized

Building geothermal projects near Fort Nelson, would help electrify new industrial load there. This could likely save BC Hydro ratepayers hundreds of millions of dollars by avoiding or delaying the need to build a new North East Transmission Line at an estimated $1 billion. In addition, some of the most promising areas for geothermal development are located at the end of transmission lines. Such is the case with Valemount, BC. These areas experience frequent power outages (brownouts), and have restricted economic growth. This situation can be remedied through the strategic deployment of geothermal power projects throughout the province.

5) Strengthens the Grid Through Ancillary Services, Including Geothermal Energy’s Unique Base Load and Dispatchable Capacity

Jurisdictions worldwide recognize the benefit to their power grids of incorporating energy sources that either have a base load capacity, and/or are dispatchable. The advantages accruing from such characteristics are referred to as ancillary services. Neither wind, solar nor run of river hydro possesses both of these characteristics. In contrast, geothermal power is both a base load source of energy, and is also dispatchable. Dispatchable energy sources are essentially those that can be ramped up and down by operators. While the Site C project is dispatchable to some degree, it is not able to do so as effectively as geothermal energy.

As is done in the State of California, these characteristics should be financially recognized in British Columbia. By providing dependable capacity, geothermal power has the potential to shape, firm and help integrate intermittent and other renewable sources such as wind, solar and run of river hydro onto the grid. These positive ancillary services can also be used to maximize profits from power exports. This is a policy objective of the Site C project.
A further benefit of geothermal power production is that in colder climates, like Canada, there is the ability to generate more power output in the winter months. This matches well with the “winter peaking” electrical grid that exists within BC.

6) Geothermal Fluids Create Strategically Significant Mineral and Rare Earth Elements Recovery Opportunities

Geothermal brine contains various minerals, rare earth elements and near earth elements, which can be extracted prior to reinjection into the ground. An example of this is the U.S. company, Simbol Materials, which has developed a process for doing this with lithium. Lithium is a valuable material used in the production of electric vehicles. The company has also demonstrated the ability to extract manganese, zinc and potassium. Many more minerals and elements are believed to be capable of extraction. These materials are used in the production of a variety of important technologies, including computers, mobile phones, missiles and other national defense systems. China currently produces a considerable amount of the world’s supply of these materials. Therefore, geothermal energy's ability to enable the cost-effective extraction of such minerals and rare earth elements is strategically significant, as it can enable Canada to be self-sufficient with respect to these commodities. It will also serve to enhance the cost-effectiveness of geothermal projects.

Importantly, recovery of rare earth elements can be accomplished in a manner that does not adversely impact the surrounding environment. For example, binary geothermal power plants operate in a closed loop system, so that all withdrawn groundwater is reinjected.

7) Geothermal Power Plants Can be Built to Meet Demand and Manage or Reduce the Risk of Cost Overruns Associated with Large-Scale Projects

CanGEA believes that geothermal energy's benefits are best realized through the distribution of projects throughout BC. This will help to ensure that the economic benefits of geothermal projects are felt by a broad array of BC’s communities. An additional benefit of this is that geothermal power plants can be built, as needed, to meet provincial electricity demand, which significantly reduces the chances of cost overruns on a large-scale project such as Site C. This is a result of the noted tendency for smaller projects to be more managable from a fiscal perspective.

8) Geothermal Offers Increased Food Security and Price Stability

In addition to being used as a low-cost source of renewable heat, geothermal energy also has the potential to increase food security in rural and Aboriginal communities. As noted, heat, which is a byproduct of geothermal power plants, is utilized around the world as a source of
energy for greenhouses and fish farms. These can provide affordable fresh fruits and vegetables, as well as a source of protein, while also providing jobs.

Moreover, fruit and vegetable prices in the province are expected to rise 20% to 34% on account of the recent droughts in California. This price instability is worrisome when one considers that droughts and other natural disasters will become increasingly common as climate change continues. Given this, Geothermal greenhouses can produce price stability, by decreasing the degree to which imports of fruits and vegetables are relied upon. Also worthy of note is the Vancouver City Savings Credit Union’s assertion that if the average B.C. household was to spend 50% of its grocery budget on local food, up to an extra $6,457 per family would circulate in the local economy.”

Considering these points, the logic involved with flooding 12,759 ha (31,528 acres) of farmland should the Site C project proceed, is extremely questionable. That farmland and the new geothermal heated food facilities situated around the province are believed to be material societal benefits.

9) The Physical and Environmental Footprint of Geothermal is Small

Based on the submissions it received during the JRP hearings, the panel concluded that the Site C hydroelectric project would “produce fewer greenhouse gas emissions per unit of energy than any source save nuclear.” This statement is not true. Geothermal energy is recognized internationally as a clean and reliable power source with greenhouse gas emissions per unit of energy that are comparable to nuclear, and lower than hydroelectric.

As a case in point, the use of binary geothermal power plants are considered by most experts to be especially environmentally benign. They emit no, or nearly no greenhouse gases, and operate in a closed loop system, so that all withdrawn groundwater is reinjected. They also utilize a concentrated subterranean resource, and thus have a smaller physical footprint than nearly all other sources of energy, conventional and renewable alike.

10) Geothermal Offers a Means to “Green” Oil & Gas and Mining Operations Through the Use of Geothermal Energy

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4 Ibid, 1.
6 Site C Joint Review Panel, 308.
Making use of the excellent geothermal potential in northeastern BC could help to avoid the dumping of millions of tonnes of GHGs into the atmosphere from natural gas operations. Using distributed geothermal power plants to electrify gas fields and the proposed Liquefied Natural Gas (LNG) operations would have many advantages over a massive fixed resource with long transmission lines like the Site C project. This is especially true as distributed geothermal power plants have a high level of consistency and reliability.

As well, oil & gas operations produce large quantities of hot water, much of which is hot enough to be used for geothermal power production. Currently, much of this hot water is disposed of at great expense to the producer. The co-produced hot water can be used on-site for micro-power production, as a means of “greening” these operations by reducing the need to burn diesel or natural gas. Moreover, this can also increase the profitability of these operations.

In a similar way, geothermal water can be used in a variety of mining processes, including as a source of heat for the extraction of gold and silver through the heap leaching process.

CanGEA’s Five Point Plan to Become a World Leader in Geothermal:

1. **CanGEA recommends that a one-year moratorium be placed on the Site C project.**

   Given the large sums of public investment involved, the public deserves a thorough examination of all possible alternatives as the JRP advised. Indeed, there is time for this as the JRP concluded “available resources could provide adequate energy and capacity until at least 2028.”

   As mentioned, CanGEA's favourability maps, graphs, tables and datasets only pertain to 23% of the province for which data was available. The remainder of this “white space”, much of which CanGEA believes to hold vast conventional geothermal potential, remains to be studied. This should be addressed.

   CanGEA urges the BC government to aid in the completion of demonstration projects in the province. This will serve to provide a BC specific model of the true costs and benefits of geothermal power projects in the province.

2. **It is recommended that the province meet with industry experts and other interested parties to identify and correct several policy impediments to the successful development of geothermal energy in BC, so that this renewable source of power can compete with nonrenewable sources that already benefit from such treatment.**

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7 Site C Joint Review Panel, 304.
3. Relating to these efforts, the BC government should hold an industry sponsored international symposium on geothermal energy production in Vancouver in 2016. This symposium should be open to the public to ensure all interested parties have an opportunity to participate.

4. A public education program on geothermal energy production should be established. This could include support for demonstration projects to showcase the various merits of geothermal energy.

5. Geothermal energy should be referred to the BC Utilities Commission (BCUC) for review and recommendations by November 2015 in accordance section 5 of the *Utilities Commission Act*. This BCUC review should include review of CanGEA’s findings by independent international experts, as well as include a public hearing.
SECTION 1 – Key Findings

1.1 British Columbia Geothermal Resource Estimates and Favourability Maps

Zero MW of geothermal energy are in production in Canada. This is despite the presence of over 150 hot springs in the country. These are primarily located in British Columbia, Alberta, Yukon Territory and the Northwest Territories. Moreover, field studies and data from oil and gas industry reports suggest the presence of considerable geothermal potential.

Other indicators include Canada’s location on the Pacific Rim that hosts relatively young volcanic rock, and the fact that nearly every other country located along the Pacific Rim is currently producing geothermal power, or has advanced exploration programs. This volcanic region tends to be endowed with substantial geothermal potential owing to its underlying geology.

Anecdotally, the west-coast states of the US, including Alaska, have made the U.S. the world’s number one producer of geothermal power. Canada’s other continental partner, Mexico, is currently the world’s fourth largest producer. Thus, while CanGEA had not yet interpreted all of the field data to present to the Joint Review Panel of the Site C Clean Energy Project (JRP), nor developed specific Unit Energy Costs (UEC), there was certainly strong circumstantial evidence that BC was an obvious candidate for the development of geothermal energy.

CanGEA released its British Columbia Geothermal Resource Estimate Maps Project in September 2014. This included over 50 maps, tables, graphs and databases. CanGEA continued to work with the raw data, and released a resource estimate update in November 2014 to accompany the Unit Energy Cost (UEC) released in this report. The CanGEA UECs are believed to be the first BC data derived cost estimates shared broadly with the public.

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See the figure below for a depiction of the differences between the primary geothermal setting types. Especially noteworthy is that HSA are considered the least technically demanding geothermal system. In other words, they are the easiest to harness. Moreover, these HSA can be harnessed with binary geothermal power plants. They do not require Enhanced Geothermal Systems (EGS) and fracking.

As Figure 2 demonstrates, with the lowest studied recovery factor of 5%, and a relatively shallow depth of 2,500m, there is 5,700 MW of geothermal power potential suitable for Hot Sedimentary Aquifer (HSA) production in BC. It should be noted that from the outset these maps were intended to withstand thorough

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technical review. Given this, these figures were produced in accordance with the Geothermal Code for Public Reporting (Reporting Code). Moreover, they utilized an adapted Protocol for Estimating and Mapping Enhanced Geothermal Systems (EGS) Potential. This is commonly referred to as the Global Protocol. The methodology was adapted by the author of the original Global Protocol, for use with HSA. The EGS Global Protocol easily lends itself for application to HSA systems, as both are conductive temperature regimes. More information on the methodology and data sources used for this project can be found on CanGEA’s website at the cited link.

Notably, much of this capacity rests in the Hot Sedimentary Aquifer (HSA) located in the northeast region of the province, which has significant data available as a result of oil and gas development. Specifically, CanGEA used 75,160 data points in the project, which were filtered down to 18,019 data points. This data is publicly available as a result of oil and gas activity.

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It should also be considered that these MW estimates pertain to only 23% of the province for which there is data coverage. It is well understood that the volcanic rocks, which make up the preponderance of the ‘white space’ outside of BC’s current data coverage, have considerable geothermal potential as well, although insufficient data exists to properly characterize them according to the Geothermal Reporting Code. Enhanced Geothermal Systems, which are found in granitic rocks, have also been excluded from the MW estimates presented above.

One should keep in mind that the HSA at a 2.5 km depth represent a geothermal system with relatively low drilling costs, and an extremely low risk of dry holes due to the geothermal potential already being discovered by the oil and gas industry. As a result of this prior resource exploration, this area has excellent accessibility. As an example, the image below shows the access routes and land that has been cleared which already exists in many parts of northeastern BC.

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Also of note is the fact that geothermal production can co-exist alongside oil and gas production and indeed incremental power can even come from co-produced fluids.

CanGEA’s geothermal resource estimates fill a knowledge gap that was acknowledged by BC Hydro at the JRP hearings. BC Hydro viewed geothermal energy as possible only “in proven areas where they understand the geology.”\textsuperscript{16} Nevertheless, BC Hydro continues to be interested in geothermal energy, saying: “we would love to see some energy sources with a good amount of dependable capacity.”\textsuperscript{17}

\begin{figure}
\centering
\includegraphics[width=\textwidth]{figure4.png}
\caption{An Example of Accessible Resources}
\end{figure}

\begin{flushleft}
\textsuperscript{17} Reimann, 154.
\end{flushleft}
SECTION 2 - CanGEA’s 10 Points Towards Assessing the True Value of Geothermal Energy

During the Joint Review Panel hearings, BC Hydro based their cost estimates pertaining to geothermal projects on their Resource Options Data (RODAT). Appendix C displays this data. CanGEA found there to be the following advantages to geothermal power projects, which BC Hydro had either not addressed, or were not adequately quantified by BC Hydro. A majority of these were primarily economic considerations:

1. Geothermal Power Has a Lower UEC and Capital Cost
2. Geothermal Heat is a Valuable By-Product
3. More Permanent Jobs are Generated by Geothermal Operations Than Other Alternatives
4. Costly BC Hydro System Transmission Upgrades are Avoided or Minimized
5. The Power Grid is Strengthened Through Ancillary Services, Including Geothermal Energy’s Unique Base Load and Dispatchable Capacity
6. Geothermal Fluids Create Strategically Significant Mineral and Rare Earth Elements Recovery Opportunities
7. Geothermal Power Plants can be Built to Meet Demand and Manage or Reduce the Risk of Cost Overruns Associated With Large-Scale Projects

However, CanGEA also found there to be the following socio-economic and environmental considerations that had not been quantified by BC Hydro:

8. Geothermal Offers Increased Food Security and Price Stability
9. The Physical and Environmental Footprint of Geothermal is Small
10. Geothermal Offers a Means to “Green” Oil & Gas and Mining Operations

2.1 Economic Benefits

2.1.1 Geothermal Power Has a Lower UEC and Capital Cost

The RODAT data that was discussed earlier is a series of data sheets covering various potential energy sources, including: geothermal, wind, hydro, demand-side management, and others. Of particular interest is the RODAT section evaluating potential geothermal energy projects. The geothermal energy data is displayed in Appendix C.

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18 BC Hydro, 2013.
The Unit Energy Cost (UEC) for the bundle of geothermal energy projects that BC Hydro selected was $127/MWh. BC Hydro noted that such estimates are only “a rough unit energy cost”.19

Interestingly some of the projects in this selection had UECs as high as $179/MWh. CanGEA takes issue with the rationale behind including projects with UECs this high. These projects do not meet CanGEA’s surface and subsurface favourability approach to project development, and were therefore omitted by CanGEA in this report until further research in these areas is carried out.

CanGEA is confident based on the analysis presented in this report that there are far more economically viable alternatives elsewhere in the province. The inclusion of these presently “out of the market” geothermal projects needlessly inflates the overall UEC of the geothermal project portfolio. Furthermore, CanGEA questions some of the underlying assumptions in the RODAT. For instance, the plant life and the capacity factor for geothermal power plants, both flash and binary, was found to be too low. Therefore, these assumptions were adjusted to reflect expected operating conditions in BC, and to recognize the true long lasting and dependable capacity of geothermal power plants.

To gain a more informed and up to date picture of the cost to produce geothermal electricity, CanGEA member developers and engineering consultants with extensive experience in geothermal development were consulted. From these sources the most current data regarding costs and performance of geothermal generating facilities was obtained.

The 15 geothermal projects that had been included in BC Hydro’s latest RODAT were then reviewed to see how this updated information would impact on the BC Hydro calculated UECs. The 15 projects fell into two broad categories:

1. 6 were deemed higher temperature resources, located in generally volcanic geology, that would most likely use flash-steam generation technology (the “Flash Plants”)
2. 9 were deemed lower temperature resources that would most likely use binary-cycle technology (the “Binary Plants”)

The highest cost project in each category was dropped, as they would be the least likely to be developed in the near future. One must also keep in mind that some geothermal potential, by its very nature, is inaccessible as it is in protected in national or provincial parks. Geothermal potential that resides in (very) remote areas is also inaccessible due to the potential resource being significantly far from a load center.

Taking these considerations into account resulted in CanGEA selecting a number of likely baskets of geothermal power project opportunities in the province, which are significantly different than the ones that BC Hydro presented to the

19 Reimann, 156.
JRP. This revision of the project portfolio allowed for updated UECs to be calculated.

This updated information produced new values for plant operating life, availability and capacity factors. It also gave capital costs and operating costs for binary plants. For the flash plant portfolio, RODAT capital and operating costs were retained, although these, too, need further investigation.

The revised input values were then fed into a model that calculated updated UECs in the same way that the UECs had been calculated for the RODAT. The comparative results are illustrated in the following chart:

In addition to the 5 flash and 8 binary projects from the original RODAT set, a series of new binary projects that had not previously been considered were also added to the portfolio. These additional projects have since come to light as a result of the extensive data gathering, resource estimating and favourability mapping conducted by CanGEA over the past two years, and have been vetted through our CanGEA developer members. The review was also performed by engineering consultants and a global expert (Qualified Person) in resource estimation.

There are a great many potential sites for HSA projects in the sedimentary basins of BC, and they have easy access plus extensive current data on the HSA geothermal potential that is coincident with the oil and gas development in the region. However, for comparative purposes, the chart includes only one site at 11 MW and several sites at 15 MW.
The graph shows very clearly that using the updated data, BC’s geothermal energy has an enormous potential to supply the province’s electricity needs, at a cost that is very competitive with any other source, including Site C.

The 14 updated binary plants charted have the potential to supply 2,300 GWh/yr at costs under $81/MWh, and there are many more such plants possible given the resource potential in the northeast area of BC, as well as spread around the remainder of the province.

The 5 updated flash plant sites that have already been identified, have the potential to supply another 4,200 GWh/yr, at costs of $80 to $90/MWh, and there are many other potential sites spread around the province as well. It’s a matter of government (and the Crown utility) having the will to drive that development forward.

CanGEA’s preferred portfolio, however, based on our research, shows that there are other possible geothermal projects that are useful for the purposes of comparison to the Site C project. Using only binary plants, which includes the 8 conventional binary plants from the RODAT with 28 HSA plants, 5,100 GWh/yr could be generated at an average cost of only $73/MWh, and a total capital expenditure (CapEx) of only $3.3 billion. Notably, this portfolio would be $10 less costly than the RODAT Site C estimate of $83/MWh. Furthermore, it would be less than half as costly, given Site C’s CapEx is stated at $7.9 billion.

Site C will inevitably have a high transmission cost, while the strategic dispersion of geothermal projects will be able to minimize transmission costs. Thus, there is every reason to believe that given the thoughtful and methodological development of BCs geothermal potential, geothermal power could provide all of BC’s future power requirements at a lower cost to ratepayers than the proposed Site C project.

The HSA binary plants could be located in any of BC’s sedimentary basins. In the northeast, they could be located adjacent to gas development and production, to facilitate direct electrification much more quickly than by the building of long and expensive transmission lines. In central or southeast BC, they could be located to provide clean, reliable, base load power and ancillary services directly to the BC electricity grid.

2.1.2 Geothermal Heat is a Valuable By-Product

Unlike in many countries, geothermal energy has a lack of awareness and high profile in Canada. Therefore, it is important to highlight that where one finds excellent potential for geothermal power, they also find a significant source of low-cost, clean and renewable heat. In addition, a majority of applications using this heat require geothermal fluids of a much lower temperature than that required for power generation. As a case in point, geothermal direct use generally uses temperatures of between 50°C and 150°C, which tend to be more
abundant and located at shallower depths.\textsuperscript{20} The use of this heat for commercial and industrial purposes is known as the direct use of geothermal energy, or “direct use” for short.

Moreover, geothermal direct use offers the opportunity for community economic capacity building, which can be done in addition to, or separate from power production. This is an important trait of geothermal energy that must be considered, as proposed energy projects such as Site C lack this benefit.

While geothermal power generation is an extremely viable proposition in its own right, often overlooked are the positive economic and social effects that can be gained from utilizing geothermal energy for direct use. While one is virtually limited by only their imagination in terms of what can be done with this potential, this section will briefly cover a few of the most obvious applications.

CanGEA’s previously released report on the direct use of geothermal heat details over 50 known applications.\textsuperscript{21} With regards to Canada specifically, aquaculture operations, greenhouses, agricultural drying, hot springs, spas, industrial process heating, space conditioning, and snow melting, were in the opinion of CanGEA’s experts, the best-suited applications for the direct use of geothermal heat.\textsuperscript{22} While, there is no intention to duplicate this research, there is merit in briefly discussing some of these applications, especially in the context of the Site C project.

\textsuperscript{21} Bakhteyar et al., X.
\textsuperscript{22} Ibid.
In recent years one of the most popular direct use applications has been the development of geothermal aquaculture. This essentially entails the rearing of freshwater or marine species using a controlled environment in order to enhance production rates. As CanGEA’s direct use report notes, “When water temperature falls below an optimum range, the basic body metabolism of fish is altered, causing them to lose their ability to feed.”23 Given this, geothermal energy can maintain water temperature much better than the sun, and therefore presents a potentially lucrative opportunity for fish farmers. Aquatic species that can be raised using geothermal heat include: carp, catfish, bass, tilapia, frogs, mullets, eels, salmon, sturgeon, shrimp, lobster, crayfish, crabs, oysters, clams, scallops, mussels, abalone, and alligators.24

As a demonstration of the possibilities for such operations, in Klamath Falls, Oregon tropical fish were raised in direct use geothermal heated ponds. This operation has since switched to Tilapia production due to decreasing demand for luxury items as a result of the 2008 global financial crisis. Nevertheless, African cichlids from Lake Malawi were raised in ponds kept at 23°C, and were well suited to the geothermal water, since it is similar to that of their native water body. Approximately, 1,000 fish were produced each week and trucked to San Francisco, where they were sold for stocking aquariums. The amount of savings in terms of heat through using geothermal energy was estimated at US $100,000 per year.25

Another significant opportunity lies in the use of geothermal energy for the heating of greenhouses. Research undertaken by the International Energy agency (IEA), places the production costs of geothermal heating for greenhouses at between USD 45/MWh and USD 50/MWh.26 As detailed in CanGEA’s direct use report, marketable crops have been developed in geothermal heated greenhouses in Hungary, Russia, New Zealand, Japan, Iceland, China, Tunisia, Kenya and the United States.27 Crops grown in these greenhouses include: vegetables such as cucumbers and tomatoes, flowers, houseplants, tree seedlings and cacti. The primary opportunity lies in reducing operating costs through reducing the price of heat, which can account for up to 35% of the production cost.28

Such reductions in heating costs allows for these operations to be economical in colder climates, where fossil fuel heating would not be. However, the true opportunity lies in harnessing all of the positive aspects of geothermal energy. One of the most successful greenhouse operations in the world, the Oserian Company in the Great Rift Valley of Kenya, has 50 hectares of geothermal heated greenhouses raising long-stem roses for export. This operation relies upon two small geothermal power plants that provide energy for all of the operation’s

23 Bakhteyar et al., 8.
24 Ibid.
25 Ibid., 10.
27 Bakhteyar et al., 10.
28 Ibid.
activities. The operation also utilizes the water destined for reinjection to first be used for heating. CO₂ is also captured from this fluid and piped back into the greenhouses in order to enhance growth.²⁹

Geothermal direct use has also been used around the world to provide an inexpensive source of district heating. A good example of this continentally is the Klamath Falls district geothermal heating system in the U.S. state of Oregon.³⁰ This system began operation in 1991, and in 1992 the city began marketing the district heating system to other buildings. In 2006 the city was at a financial breakeven point on the system, and provided businesses with geothermal heat set at 80% of the commercial cost of natural gas.³¹ The system currently provides process heating for the local wastewater treatment plant, as well as 24 buildings. It also provides heating for various greenhouses totaling 150,000 sq. ft., as well as approximately 105,000 sq. ft. of sidewalk snow melt systems.³² Notably, a local brewery also utilizes the system for all of its heating needs, including the brewing fermentation process and to warm its onsite restaurant.

The term “cascading” is used to describe the specific utilization of geothermal heat so that several applications are arranged to make use of the hot water resource at varying temperatures.³³ The figure below provides an example of this and gives one an idea of the immense possibilities associated with geothermal energy production.

![Figure 6: An Example of Cascading for Direct Use and Power](image)

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²⁹ Bakhteyar et al., 10.
³¹ Brown, 190.
³² Ibid., 185.
³³ Bakhteyar, 6.
³⁴ Ibid., 28.
Thus, in terms of the Site C proposal, the failure to include the value arising from the direct use of geothermal heat can certainly be said to be noteworthy. In particular, such benefits are extremely promising for BC's First Peoples, rural communities and entrepreneurs.

2.1.3 More Permanent Jobs are Generated by Geothermal Operations Than Other Alternatives

As with many other aspects of the Site C hydroelectric project, the forecast employment benefits of the project happen in one short and sudden burst. By BC Hydro’s own estimates, only 160 permanent jobs will be created by the project following its construction. By its own account, only 100 of these will be directly related to the project. This works out to 0.15 permanent jobs created per MW.

*Figure 9* below provides a comparison of the Site C project with equivalent natural gas fired power projects and geothermal power projects in terms of job creation. In their defense of Site C, BC Hydro claims that 33,000 temporary construction jobs will be created. While the dam will have very permanent effects upon large tracks of land that is altered by it, nearly all of the jobs that it will create will be temporary and disappear once the project is developed.

![Table of Employment Comparison](image)

### Table: Comparative Employment from 1,100 MW

<table>
<thead>
<tr>
<th>Power Source</th>
<th>Construction Employment (jobs/MW)</th>
<th>Operation &amp; Maintenance Employment (jobs/MW)</th>
<th>Total Temporary Employment for 1,100 MW Capacity</th>
<th>Total Permanent Employment for 1,100 MW Capacity</th>
<th>Total Employment for 1,100 MW Capacity</th>
</tr>
</thead>
<tbody>
<tr>
<td>Geothermal</td>
<td>4.0</td>
<td>1.7</td>
<td>4,400</td>
<td>1,870</td>
<td>6,270</td>
</tr>
<tr>
<td>Natural Gas</td>
<td>1.0</td>
<td>0.1</td>
<td>1,100</td>
<td>110</td>
<td>1,210</td>
</tr>
<tr>
<td>Site C</td>
<td>30</td>
<td>0.15</td>
<td>33,000</td>
<td>165</td>
<td>33,165</td>
</tr>
</tbody>
</table>

*Figure 7: Comparative Employment from 1,100 MW*

The development of 1,100 MW of geothermal energy would have quite different effects. While still substantial in comparison to other energy projects, 1,100 MW of geothermal power would create 4,400 temporary construction jobs. In addition, according to the U.S. DOE it would create 1,870 permanent jobs, which like geothermal power, is sustainable over the long-term. See *Figure 9*. It should be noted further that the vast majority of these jobs would be full-time. Also worthy of consideration is the fact that this does not include any of the employment created by the utilization of geothermal heat, nor from the extraction of materials from geothermal brine and the co-production of power.

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36 Adapted from: Geothermal Technologies Program (DOE) and Site C Clean Energy Project, 3.
2.1.4 Costly BC Hydro System Transmission Upgrades are Avoided or Minimized

Depending upon the location of geothermal projects, they can improve BC Hydro’s existing transmission network. Moreover, they can help customers by improving local electricity service and reducing BC Hydro’s costs in these areas. For instance, purchasing electricity from a base load project located at the end of a long radial transmission line, will improve the level of electricity service and reliability to local customers. An example of this is the Canoe Reach geothermal project, currently in the feasibility stage, located near Valemount, BC.\(^{39}\) This region is known for frequent power outages, as a result of its location at the end of a 325 km long 138 kV radial transmission line.\(^{40}\) Placing base load capacity near Valemount will not only secure electrical service in this region, but it will also negate the need for expensive upgrades on the existing power line. This will help reduce some pressure to increase electricity rates. It will also help to avoid economic damages caused by brown-outs.

Other opportunities for geothermal projects include building geothermal projects near Fort Nelson, which would help electrify new industrial load there. This would save BC Hydro ratepayers by avoiding or delaying the need to build a very long, high voltage transmission line. Deferring the construction of the $1 billion North East Transmission Line (to Fort Nelson) is a significant value.

In relation to this, deferring the upgrading of the existing transmission line from Prince George to the Terrace area, estimated at around $125 million, would also save BC Hydro a substantial sum of money. Taken together then, geothermal energy has the potential to save ratepayers and BC Hydro substantial sums, as it would delay, or eliminate the need to build or upgrade transmission lines.

2.1.5 Strengthens the Grid through Ancillary Services, Including Geothermal Energy’s Unique Base Load and Dispatchable Capacity

As these are technical issues, it is important to define exactly what is meant by the terms “ancillary services”, “base load”, and “dispatchable”. With regards to ancillary services, the U.S. Federal Energy Regulatory Commission (FERC) defines them as “the services necessary to support the transmission of electricity from a supplier to a purchaser, given the obligations of a control area and that area’s transmitting utilities to maintain reliable operations of the interconnected transmission system.”\(^{41}\) Taking this into consideration, there are generally


\(^{40}\) Craig Dunn, “Geothermal site holds potential for future generations” CanadianMining Journal, (May 1, 2013).

considered to be six categories of ancillary services, which include:

1) scheduling and dispatch
2) reactive power and voltage control
3) loss compensation
4) load following
5) system protection
6) energy imbalance

The consideration of such characteristics has become more important for regulatory agencies, given the increased integration of intermittent or variable sources of power such as wind, solar and run of river hydro.

When first developed, especially in the BC context, intermittent energy sources were primarily envisioned to be “backed-up” by more reliable power sources such as large hydro. However, many experts expect climate change to adversely impact water availability in Alberta and British Columbia in the future, and “climate-induced droughts are projected to reduce hydroelectric generation.” Within this context, geothermal energy’s base load capacity is of special note. A simple definition of the term “base load”, is essentially the minimum amount of power that a utility or distribution company must generate for its customers, or essentially the smallest amount of power that is needed to fulfill the minimum demands of the expected requirements of consumers.

In regards to this, geothermal power plants often exceed hydroelectric projects in terms of their operating capacity, especially when taking into consideration the challenges posed by climates with frigid winters, and the aforementioned expectations with regards to climate change. As a case in point, new geothermal power plants average in the 95% range in terms of operating capacity. Demonstrative of such reliability are the following projects operated by U.S. Geothermal. The company’s Neal Hot Springs project in Oregon, reported a 99.1% capacity factor in its most recent financial quarter, a 96.1% capacity at its project at San Emidio in Nevada, and a 99.7% capacity factor for its project at Raft River in Idaho. This exceptional base load capacity has been well recognized by both international and domestic experts. Figure 10 demonstrates a comparison of the capacity factors of various energy sources, which was taken from a report released by the Canadian Geological Survey.

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42 Matek, October 2013, 4.
44 Scorah et al., 536-537.
45 Matek, October 2013, 5.
Such high capacity factors are testament to the attractiveness of geothermal energy as a base load energy source, however it does not consider some of the other traits that make geothermal energy such a valuable contributor to electrical grids. For example, many modern geothermal power plants are able to ramp production up and down multiple times per day, from a minimum of 10% of nominal power, up to 100% of nominal power output. This ability to be ramped up and down makes geothermal energy a dispatchable energy source, as it possesses the ability to be controlled by a system operator, and “to be turned on and off” or ramped up and down.

Decisions with regards to ramping up and down are generally based upon the economic attractiveness both to supply electricity and to supply network reliability services. It is worthy to quote at length, the thought process generally involved in such decisions. “Supplies from conventional dispatchable generators are typically increased or decreased by the system operator to meet demand by dispatching the generators to supply power with the lowest marginal generation cost or bid offer price first and then moving up the ‘dispatch curve,’ calling on generators with higher marginal costs or bid prices until the demand for electricity is satisfied in real time.”

To keep things simple, and ignoring market power considerations, conventional base load generators are typically dispatched when the wholesale market price for power exceeds their short-run marginal cost of generating electricity. In

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49 Matek, October 2013, 12.
51 Joskow, 238.
considering this, intermittent energy sources cannot react to such market forces in quite the same way, as the rate at which their turbines rotate is dependent upon variables such as wind speed.

Base load energy sources also enable transmission efficiency, as 100 MW of intermittent energy capacity requires 100 MW of transmission, despite the fact that it will seldom fully utilize this.\textsuperscript{52} This is not the case with geothermal energy.

Intermittent energy sources are typically understood to be attachable, at will, to the transmission grid. However, as these power sources are not dispatchable, only at the current relative low levels of grid penetration is such a situation manageable.\textsuperscript{53} This is largely a result of the fact that present transmission lines were not designed to deliver large amounts of fluctuating levels of power. When this is the case, transmission operators must “condition” the power.\textsuperscript{54} “This requires intense attention to the moment-by-moment condition of the power in the lines; it is expensive, and is awkward compared to handling dispatchable power.”\textsuperscript{55} In contrast, dispatchable power is understood by grid operators, and electric utilities know how to move and control it. Moreover, it is the power source that grid systems have historically been designed for.\textsuperscript{56}

It is important to be clear that these attributes do not hold that there is no place on the grid for intermittent energy sources. Rather, geothermal energy’s base load and dispatchable qualities actually strengthen the grid, allowing for more intermittent energy sources, e.g., wind, solar and run of river hydro, to be used. Moreover, recent research models have demonstrated the ability of hybridization between solar systems and binary geothermal systems to enhance the production and reliability of both.\textsuperscript{57}

In consideration of these arguments, it is worthy to note that state governments in the U.S. have moved towards recognizing the value of such characteristics. For instance, in September 2014 the California Governor signed Assembly Bill 2363 into law.\textsuperscript{58} This law requires the California Public Utilities Commission to create “adders” or “integration costs” for the evaluation of energy technologies, and that these must be used in the awarding of long-term wholesale power contracts. This change addresses the concerns raised above, and also places the appropriate costs to solar, wind power and run of river hydro. The result of this is to allow for base load renewables such as biomass and geothermal energy to compete for Power Purchasing Agreements (PPAs) based on a more accurate comparison of the full cost for power.

\textsuperscript{52} Matek, October 2013, 12-13.
\textsuperscript{54} Lee and Gushee, 22.
\textsuperscript{55} Ibid.
\textsuperscript{56} Ibid, 23.
\textsuperscript{58} California Legislative Counsel, “Assembly Bill No. 2363” California State Assembly, (Sacramento: California: September 26, 2014).
A further benefit of geothermal power production is that in colder climates, like Canada, there is the ability to generate more power output in the winter months. This matches well with the “winter peaking” electrical grid that exists within BC.

2.1.6 Geothermal Fluids Create Strategically Significant Mineral and Rare Earth Elements Recovery Opportunities

As a recent Stanford University report notes, in addition to hybrid development with intermittent energy sources, and co-production with oil and gas activity; “Coupling mineral extraction methods with geothermal power production offers potential benefits via added revenue and increased operational efficiencies.” In terms of added revenue, minerals commonly found in geothermal fluids include: silica, lithium, manganese, zinc and sulphur. Moreover, additional Rare Earth Elements (REE) and Near Rare Earth Elements (NREE) have also been noted to be relatively prevalent in geothermal brines. As mentioned in the Stanford report, these chemical elements not only carry significant market value, but they also hold strategic significance as they are used in the production of everything from mobile phones, to national defense systems. This has become especially true in recent decades, as the world’s supply of REEs has almost entirely shifted to China.

Figure 11 shows the known REE and mineral deposits in the US. Logic would suggest that such deposits do not adhere to political boundaries, and that Canada also holds vast amounts of these precious materials. Indeed, precious metals will concentrate within hydrothermal systems.

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60 Segneri et al., 1.
61 Ibid.
This quite obviously presents an opportunity with regards to geothermal energy production. As noted, such minerals and elements represent a business opportunity in and of themselves. However, the extraction and subsequent sale of these also has the potential of decreasing already low geothermal operating and maintenance costs. This arises as a result of the fact that the need for repairs to geothermal plant parts often results from corrosion and scaling caused by mineral-rich geothermal brine. Thus, the extraction of these could result in an extended operational life for parts that come into contact with geothermal fluids. As discussed, there is also the likelihood that geothermal energy could be used to power these operations, which would serve to extend their social license as well as decrease their energy costs.

Taken together, the extraction of minerals and REEs has the possibility of significantly increasing the economic attractiveness of geothermal power operations. As a knowledgeable source on the subject is quoted: “There are something like 30 strategic minerals that flow through power plants right now. It would be the Holy Grail of mining to be able to produce all of that from a geothermal well.”

The U.S. Company, Simbol Materials, is illustrative of the fact that this is far from simply a futuristic concept. The company is backed by the large Japanese trading firm, Itochu, and set out almost five years ago to produce large volumes of

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62 Segneri et al., 13.
63 Ibid., 1.
lithium and other valuable minerals from geothermal brines in California.\textsuperscript{65} The extracted lithium carbonate was to be used in the production of critical components needed in the electrical vehicle market.\textsuperscript{66} The company eventually created a demonstration plant in Calipatria, California, which draws its brine from a \textasciitilde{}50 MW geothermal project owned by EnergySource.\textsuperscript{67} As of February 2014, the plant had turned out 100 tonnes of lithium, which Simbol has sold to various companies for field-testing.\textsuperscript{68} Aside from lithium, the project has also demonstrated the ability to remove manganese, zinc and potassium, though the focus remains upon lithium. Such developments led to the February 14, 2014, announcement that the U.S. Department Of Energy (DOE) will provide research grants to similar projects as a result of their strategic importance.\textsuperscript{69}

### 2.1.7 Geothermal Power Plants Can be Built to Meet Demand and Manage or Reduce the Risk of Cost Overruns Associated with Large-Scale Projects

Geothermal power plants are generally not “mega-projects”. As one can discern, this is likely not even desirable, as the benefits that geothermal energy holds for communities via direct use of heat, can be better realized through the distribution of projects in various areas. A useful byproduct of developing geothermal power plants is the fact that these plants will allow for build out in accordance with electricity demand. This will avoid risks of excess supply due to less than expected future demand. A recent report produced for the Clean Energy Association of British Columbia (CEBC) by London Economics International (LEI), addressed these concerns at length.\textsuperscript{70}

Another important point in terms of the geothermal power option is that smaller projects are much easier to manage for cost overruns. Moreover, they allow for adjustments and adaptability, which is not enabled in the same manner for larger projects.

\textsuperscript{66} Coons, 35.
\textsuperscript{68} Kaufmann.
\textsuperscript{69} Ibid.
2.2 – Socio-Economic Benefits

2.2.1 Geothermal Offers Increased Food Security and Price Stability

It has been noted by many researchers that population growth, coupled with intense economic, environmental, and social change has led to the acceleration of globalized food networks and supplies. The resulting marketing of profitable industrial food products has been so successful that it has developed serious health consequences for people around the world. This has resulted in an upsurge in non-communicable diseases such as cardiovascular illness, diabetes, and cancer. Researchers in the field have termed this the "nutrition transition" and note that Indigenous peoples around the world have experienced this transition, despite the presence of a wealth of traditional knowledge regarding how to eat well. While the types of food available to consumers is certainly an issue, so too is the cost of healthy alternatives. Combined with the generally high costs for other necessities, such as energy provided by expensive diesel fired generators, a sort of perfect storm is created in many remote and Aboriginal communities.

However, research shows that BC’s food security is also in question more generally, due to increasing levels of price instability. As a case in point, the province has become dependent upon fruit and vegetable imports from the U.S. Testament to this is the fact that in 2010, 67% of the province’s vegetable imports came from the U.S., and half of these came from California. Moreover, 95% of all the U.S.’s broccoli and 74% of all lettuce are produced in California. In a world market that will increasingly have to face the repercussions of climate change, this food dependence is worrisome. Demonstrative of the validity of these concerns are the recent droughts faced by California, and the fact that they are expected to drive up fruit and vegetable prices by 20% to 34%.

Given this, geothermal energy’s direct use of heat applications for fish farming and greenhouse-produced food, can increase the food security of remote and Aboriginal communities. It can also help to produce price stability more generally, by decreasing the degree to which imports of fruits and vegetables are relied upon. Also worthy of note is the Vancouver City Savings Credit Union’s study finding that if the average B.C. household was to spend 50% of its grocery budget on local food, up to an extra $6,457 per family would circulate in the local

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73 Vancity, 1.
74 Ibid.
75 Ibid.
Considering the above points, the logic involved with flooding 12,759 ha (31,528 acres) of farmland should the Site C project proceed, is extremely questionable. Wendy Holm, a noted agrologist, contends, “The lands to be flooded by the dam could feed up to over a million British Columbians.” This is concerning, especially at a time when California farmland, and in particular irrigated California farmland, is disappearing due to the prevalence of drought. That farmland and the new geothermal heated food facilities situated around the province are believed to be material societal benefits.

2.3 – Environmental Benefits

2.3.1 The Physical and Environmental Footprint of Geothermal is Small

Geothermal power is classified as a renewable energy source, and as such, is categorized with solar, wind and biomass. While beyond the scope of this report, it should be noted that hydroelectric dams such as Site C are not correctly identified as renewable energy sources. In fact, environmental impact assessment experts attest that on a comparative basis, much “greater environmental losses are associated with hydroelectric power relative to geothermal development.” These include biological damage from the losses of various organisms, species, soils, ecosystem components and ecosystem services. In addition, there are also significant hydrological impacts upon lakes, ponds and rivers, as well as downstream geomorphological effects. Finally there are also often cultural losses as a result of reservoir impoundment.

In addition there are the obvious effects that such projects have upon the physical beauty of their landscapes. Indeed, the environmental effects associated with the Site C project have been studied at length elsewhere, so an in-depth discussion of these is not warranted here.

Nonetheless, it is important to note that geothermal power plants are recognized by most experts to create “much lower emission of greenhouse gases than most other technologies.” This holds true for geothermal direct use of heat projects as well. Of particular note is the fact that binary geothermal power plants, the

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76 Vancity, 1.
77 Peace Valley Environment Association, 3.
79 Peace Valley Environment Association, 4.
82 Thórhallsdóttir, 540.
83 Rybach, 467.
type that CanGEA envisions for Canada, are an especially environmentally benign energy source.\textsuperscript{84} Experts on the subject have determined the life cycle effects of such plants, especially when used for direct use of heat in accordance with power production, to be very limited.\textsuperscript{85}

![Environmental Footprint for Various Techniques](images/10.png)

The physical footprint of geothermal projects is also very small, even compared to other renewable sources. Unlike solar, wind and biomass, which are based upon gathering energy from “diffuse ambient energy over large tracts of land”, geothermal energy utilizes a concentrated subterranean resource.\textsuperscript{87} Certainly then, even multiple geothermal projects would total far less than the 5,340 hectares of land that is conservatively projected to be flooded by the Site C hydroelectric project.

2.3.2 Geothermal Offers a Means to “Green” Oil & Gas and Mining Operations

As noted in the JRP hearings, in July 25, 2012, the government of B.C. exempted “facilities that liquefy natural gas for export by ship” from section 2(c) of the

\textsuperscript{84} Peter Bayer, Ladislaus Rybach, Philipp Blum and Ralf Brauchler, “Review on life cycle environmental effects of geothermal power generation” Renewable and Sustainable Energy Reviews 26 (2013): 460.

\textsuperscript{85} Bayer et al., 460.


\textsuperscript{87} Matek, October 2013, 14.
Clean Energy Act. The result is that LNG developers are now free to use their own power for liquefaction regardless of the greenhouse gas (GHG) consequences.

Given this exemption, the JRP concluded that a ‘low-end’ load forecast was the most likely scenario. This scenario assumed that electricity would not be used for compression or liquefaction, only for plant “house load”. Under this scenario, 823 GWh/yr and 100 MW of capacity was projected, starting in 2020.

While CanGEA has reservations regarding the exemption of liquefaction from the Clean Energy Act, the projected 100 MW house load will nonetheless require a source of power. As will the natural gas operations themselves. As established by CanGEA, the northeastern HSA that is located in the same vicinity as the natural gas developments present an excellent opportunity for the sustainable electrification of these operations. As mentioned, these can be built to follow demand, and will avoid the discharge of millions of tonnes of GHGs into the atmosphere by natural gas operations. This is also true for remote mines in the region.

Using distributed geothermal power plants to electrify natural gas operations would have many advantages over a massive fixed resource with long transmission lines like the Site C project. This is especially true as distributed geothermal power plants have a high level of consistency and reliability.

Co-production represents another major opportunity for Canada’s oil and gas producing regions, and is especially relevant to northeast BC. A substantial amount of hot geothermal water is generally produced as a result of oil and gas drilling. In fact, in 2010 the U.S. DOE estimated that approximately 25 billion barrels of hot water were produced annually from oil and gas wells within the country. Prior to refining oil and gas, this water must be removed, and therefore requires costly disposal. However, if the “waste water” is warm enough and flow rates are high enough, it is possible, prior to disposal or reinjection, to run it through a binary power plant in order to generate electricity. The electricity generated can then be used in existing systems needed for oil and gas extraction, reducing a given well’s energy demand. According to the US DOE, such processes “can deliver near-term energy savings, diminish greenhouse gas emissions, extend the economic life of oil and gas fields, and profitably utilize abandoned oil and gas field infrastructure.”

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88 Site C Joint Review Panel, 284.
89 Ibid., 283.
90 Ibid.
93 Grasby et al., 38-39.
94 National Renewable Energy Laboratory, 2.
In consideration of this, there is groundbreaking work being done on co-production in Casper, Wyoming, at the Rocky Mountain Oil Testing Center. A 0.25 MW geothermal hydrocarbon coproduction unit has been installed. It is estimated that the unit will pay for itself within 7 years, and that it has the potential to turn a profit of $2.5 million, over 25 years.\(^95\) As well, the University of North Dakota is developing two demonstration projects that will use binary technology to produce electricity from low temperature fluids. One will have an estimated capacity of between 0.35 and 0.568 MW, and the other will have an estimated capacity of 0.25 MW.\(^96\)

Also worthy of note is Chena Power LLC, which has developed a mobile geothermal power plant. This plant was funded by the U.S. DOE, and showcases low-temperature, co-produced resources, and their use for power generation.\(^97\) Their first power plant was deployed in May 2010, in Utah, at a site with existing oil and gas wells with known geothermal potential. The project is scheduled to end in December 2014, and is expected to reduce development costs, as well as permitting costs for geothermal power projects.\(^98\) This is especially applicable to the Site C project, as it demonstrates that the development of future geothermal projects in northeastern BC will likely have significantly reduced costs in terms of both time and money.

Turning attention back to the Western Canada Sedimentary basin that BC hosts in its NE corner, the graphic below gives a dramatic picture of how much resource water is available. There was one co-production demonstration project being developed near Edmonton, Alberta, however this demonstration project has not proceeded due to non-technical reasons. Nevertheless, the Geological Survey of Canada was a strong proponent of such research, stating that it promises to “support growth for geothermal power production in oil fields across other regions of Canada where temperatures and flow rates support such technology”\(^99\) In relation to this, BC currently has several oil and gas producing regions. These include the Bowser basin, the Nechako basin, and the Western Canada Sedimentary Basin. As indicated above, the fact that research into geothermal co-production has been pursued so aggressively in the U.S. suggests that there is substantial merit to this application of micro-geothermal power.

\(^97\) National Renewable Energy Laboratory, 2.
\(^98\) Ibid.
\(^99\) Matek, April 2014, 29.
It is important to note that CanGEA’s geothermal resource estimate for BC does not consider the contribution of co-produced wells from the HSA that it studied. Rather, the HSA can also be produced directly for geothermal power.

Geothermal fluids are also utilized globally in various mineral extraction processes. Most applicable is the practice of using geothermal fluids in the heap leaching process, in order to extract gold and silver. This process essentially involves stacking metal-bearing ore into “heaps” on impermeable pads for extended periods of time, and using a chemical solution to dissolve the sought-after metals. This creates what is known as “pregnant solution”, which can be processed into commercially viable final products. Geothermal fluids are used for both direct and indirect heating of various parts of this process. The most common use is as a heating source for heap leach pads, which helps to enhance the chemical processes.

A lower hanging fruit opportunity is to simply use warm mine water for the on-site heating load or entrepreneurial activities.

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102 Bakane, 31.
SECTION 3 – The Path Ahead

In our experience, BC Hydro and the BC government are demonstrating institutional inertia when it comes to harnessing the full potential of geothermal power in British Columbia. This is not surprising given the long-term commitment to hydroelectric energy production. However, it is time to adopt 21st century energy solutions.

Institutional inertia refers to the often-observed tendency for political entities to resist change. That is, political scientists have long noted that political institutions, and the bodies created by them, tend to be "excessively static and likely to remain on the same path unless some effort is made to divert them."¹⁰⁴

While at times desirable, at other times institutional inertia can preclude viable alternatives to the status quo. In our view, geothermal energy has fallen victim to this phenomenon. This report has demonstrated that geothermal energy is cost competitive to the Site C project, and offers various advantages that will be forfeited should the Site C hydroelectric project proceed.

CanGEA fully supports the need for independent verification of our findings and urges the government to adopt a five point plan to become a world leader in geothermal:

1. CanGEA recommends that a one-year moratorium be placed on the Site C project. Given the large sums of public investment involved, the BC government owes it to the public to perform a thorough and transparent examination of all possible alternatives. Indeed, there is time for this as the JRP concluded "available resources could provide adequate energy and capacity until at least 2028."¹⁰⁵ During this time, a more in-depth cost analysis can be performed with regards to geothermal power projects. Due to the highly context dependent nature of geothermal energy projects, this cost analysis would be best informed by the completion of further technical field research.

As mentioned, CanGEA’s favourability maps, graphs, tables and datasets only pertain to 23% of the province for which data was available. The remainder of this “white space”, much of which CanGEA believes to hold the province’s best potential, remains to be studied. This should be addressed.

CanGEA urges the BC government to aid in the completion of demonstration projects in the province. This will serve to provide a BC specific model of the true costs and benefits of geothermal power projects in the province.

¹⁰⁵ Site C Joint Review Panel, 304.
2. It is recommended that the province meet with industry experts and other interested parties in order to identify and correct policy impediments to the successful establishment of a geothermal industry in British Columbia. A useful starting point would be to reform the Geothermal Resources Act (GRA). Under the current act, even if developers come to the table with First Nations support, wait times of years have ensued. Moreover, even if a permit is granted, it is often smaller than the original request.

Worse, is the fact that areas of the province used by oil and gas activity have been taken out of consideration for geothermal project development. This is especially worrisome given the enormous opportunities that HSA geothermal power plants present.

Such obstructions do not exist, to this degree, with shale gas wells, wind, solar and run of river permits. Certainly, correcting such shortcomings should go a long way to ensuring that BC’s significant geothermal potential does not remain unutilized.

In order to correct this, the BC government should form a taskforce to make recommendations on the policy and regulatory changes required to support cost effective and efficient development of a geothermal industry in BC by 2020.

3. Relating to these efforts, the BC government should hold an industry sponsored international symposium on geothermal energy production in Vancouver in 2016.

4. A public education program on geothermal energy production should be established. This could include support for demonstration projects to showcase the various merits of geothermal energy.

5. Geothermal energy should be reviewed to the BC Utilities Commission for review and recommendations by November 2015 in accordance section 5 of the Utilities Commission Act. This BCUC review would include review of our findings by independent international experts, as well as include a public hearing.
Appendix A: British Columbia Geothermal Resource Estimates

<table>
<thead>
<tr>
<th>Recovery</th>
<th>Depth</th>
<th>Indicated Resources</th>
<th>Inferred Resources</th>
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<tr>
<td>5%</td>
<td>1,500m:</td>
<td>133 MW</td>
<td>0 MW</td>
</tr>
<tr>
<td>2,500m:</td>
<td>5,723 MW</td>
<td>763 MW</td>
<td></td>
</tr>
<tr>
<td>3,500m:</td>
<td>2,613 MW</td>
<td>659 MW</td>
<td></td>
</tr>
<tr>
<td><strong>Total</strong></td>
<td>8,469 MW</td>
<td>1,422 MW</td>
<td></td>
</tr>
<tr>
<td>14%</td>
<td>1,500m:</td>
<td>373 MW</td>
<td>0 MW</td>
</tr>
<tr>
<td>2,500m:</td>
<td>16,025 MW</td>
<td>2,136 MW</td>
<td></td>
</tr>
<tr>
<td>3,500m:</td>
<td>7,316 MW</td>
<td>1,846 MW</td>
<td></td>
</tr>
<tr>
<td><strong>Total</strong></td>
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<td>3,982 MW</td>
<td></td>
</tr>
<tr>
<td>20%</td>
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<td>2,500m:</td>
<td>22,893 MW</td>
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<td></td>
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<tr>
<td>3,500m:</td>
<td>10,451 MW</td>
<td>2,637 MW</td>
<td></td>
</tr>
<tr>
<td><strong>Total</strong></td>
<td>33,877 MW</td>
<td>5,688 MW</td>
<td></td>
</tr>
</tbody>
</table>

*According to the Canadian Geothermal Reporting Code*

Figure 12: Technical Potential for Geothermal in British Columbia with Corrected Bottom Hole Temperature

Figure 13: Total Technical Potential with Uncorrected Bottom Hole Temperatures at 2,500 m
Figure 14: Technical Generation Potential by Depth with 5% Recovery

Priority Geothermal Exploration Areas

Figure 15: Areas of Priority Exploration in British Columbia Based on Technical Potential
Appendix B: Addressing the Maturity of Geothermal Energy Technical Field Knowledge in British Columbia

As with any infrastructure megaproject, in one way or another the proposed Site C hydroelectric dam will have profound economic, political and social reverberations that are sure to be felt by residents of British Columbia for many years to come. With regards to this, prior analysis has generally focused upon the project’s effects upon provincial ratepayers, landowners and Independent Power Producers (IPPs).

The LEI report presented the cost-effectiveness of an alternative portfolio of clean energy projects, within the context of the Site C proposal.\textsuperscript{106} It found that such a portfolio would save between $750 million and $1 billion. This paper is useful in various regards, especially in terms of highlighting inconsistencies and points of shortcoming within the underlying cost analysis of Site C in comparison with other clean energy sources.

While informative, the LEI report did not fully explore the alternatives to the Site C proposal. Specifically, it did not include geothermal energy in its alternate portfolio due to the “current immaturity of technical field knowledge and the lack of a clear development framework (which) mean that otherwise promising geothermal projects appear to be unlikely to come to fruition within the forecast horizon.”\textsuperscript{107} While this may have been true at the time, CanGEA has since produced geothermal favourability maps, tables, graphs and datasets for the province of BC, which have sought to remedy this situation. Testament to this prior lack of knowledge was the BC Joint Review Panel’s conclusion “that a failure to pursue research over the last 30 years into B.C.’s geothermal resources has left BC Hydro without information about a resource that BC Hydro thinks may offer up to 700 megawatts of firm, economic power with low environmental costs.”\textsuperscript{108}

This lack of knowledge was hardly addressed by BC Hydro, as during the Site C JRP hearings it was acknowledged that less than $100,000 a year was spent on studying the geothermal option.\textsuperscript{109} In addition to this knowledge gap, the geothermal industry has also been held back by various policy barriers. These include the existence of an inefficient and lengthy provincial leasing scheme, especially as compared to those enjoyed by other types of natural resource based projects. It has also been significantly hindered by the aforementioned lack of research on the part of BC Hydro and other relevant government entities.

It should be acknowledged that during the JRP hearings, BC Hydro claimed that its “role is not to do R&D”.\textsuperscript{110} This is despite the fact that BC hydro felt that the province’s geothermal energy potential was promising, and that it had been

\textsuperscript{106} London Economics International LLC, 1-49.
\textsuperscript{107} Ibid., 26.
\textsuperscript{108} Site C Joint Review Panel, 299.
\textsuperscript{109} Reimann, 157.
\textsuperscript{110} Ibid., 154.
recommended prior to look into it. Such shortcomings resulted in the need for CanGEA’s maps project.

Regardless of this lack if contextual knowledge, the process enabling the utilization of geothermal energy for power production is actually a relatively mature technology. Demonstrative of this is the fact that geothermal energy has been used for commercial power production since as early as 1913.111 Moreover, its reliability as a power source has also been demonstrated, evidenced by the considerable operating life of many geothermal power projects around the world. An instructive example of this is the Wairakei Geothermal Power Project in New Zealand, which as of 2009 had been in operation for more than 50 years.112

There are two commonly used processes when creating electricity from geothermal sources. The first, flash geothermal, is generally associated with higher temperature geothermal sources ( >180°C). Because the pressure of the subsurface environment is much greater than at the Earth’s surface, water can exist as a liquid at very high temperatures. The high temperature, high-pressure water is brought to surface, where it is enters a low-pressure chamber and ‘flashes’ into steam. The pressure created by this steam is channeled through a turbine, which spins to generate electrical power. Once the steam has exited the turbine, it is either released into the atmosphere as water vapour, or it cools back into liquid water and is injected back underground.

![Figure 16: Depiction of a Flash Steam Power Plant](image)

Since the 1980s though, technological developments have enabled the use of lower temperature geothermal water for electrical production, and have facilitated the further spread of geothermal power production globally. These plants have come to be known as “binary” geothermal plants, and are the

primary plant type that CanGEA envisions in Canada. In these plants, geothermal fluids heat another liquid such as isopentane or isobutene, which boils at a lower temperature than water. Such liquids are commonly referred to as “working fluids”. During this process, the two liquids are kept completely separate through the use of a heat exchanger and are used to transfer heat energy from the geothermal water to the working fluid. When heated, the working fluid vapourizes into gas and the resulting force of the expanding gas turns the turbines that power the generators.113

In 2008, approximately 15% of all geothermal power plants employed this technology.114 By all indications this number has since grown.

![Figure 17: Depiction from General Electric of the Binary Geothermal Process](image)

Thus, while there are currently 0 MW of geothermal power produced in Canada, one must remember that geothermal power production is a mature technology. Moreover, there is a sizable international geothermal industry, since as of September 2013 geothermal power was being produced in at least 25 countries.116

In addition, as of April 2014, nearly 700 geothermal power projects were in

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development across 76 countries. There were 182 in development in the U.S. alone. Especially worthy of note is the fact that Canada is one of the only countries located along the “Pacific Ring of Fire” not to utilize this valuable potential.

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117 Matek, April 2014, 4.
Appendix C: CanGEA Mission Statement, Project Team and Biographies of Key Report Contributors

The Canadian Geothermal Energy Association (CanGEA) is the collective voice of Canada's geothermal energy industry. As a non-profit association, we engage in advocacy and public outreach efforts that promote the exploration and development of geothermal potential in Canada. Geothermal energy can provide competitively priced, renewable, round-the-clock energy to the Canadian and U.S. markets. CanGEA is not involved in the development of low temperature geothermal resources utilized for commercial and residential heating, ventilation and air-conditioning systems – usually referred to as geo-exchange or geothermal heat pump systems.

Justin Crewson, lead author
Policy Advisor – Canadian Geothermal Energy Association

Dr. Graeme Beardsmore, Competent Person/Qualified Person
Technical Director – Hot Dry Rocks

Alison Thompson, project oversight
Chair- Canadian Geothermal Energy Association

Ashley Derry, technical advisor
Geoscientist – Borealis GeoPower

Jim Weimer, Financial Consultant
Financial Consultant, Weimer Consulting Inc.

TM Gunderson, Engineering Lead
Enerpro Engineering

Alexa MacDonald, document editor
Technology Transfer Coordinator, Canadian Geothermal Energy Association

**Justin Crewson**: possesses Bachelor degrees in history and political science from Wilfrid Laurier University. He has also obtained Masters degrees in Political Science and Public Policy from the University of Windsor and the University of Michigan-Dearborn respectively. In addition to these academic credentials, Justin holds significant experience in relation to public policy. He has worked in various capacities for both the McGill Institute for the Study of International Development (ISID), and the Canada School of Public Service. In both of these roles he was involved in managing special projects and initiatives. At the McGill ISID, he was involved with managing projects involving grass roots development, and structuring the content of the institute's Executive Education Program. As well, he also worked for the Essex County Diversion Program, and worked with, and assisted in institutional responses to youth charged with criminal offences. Justin is currently the policy advisor for CanGEA.
Dr. Graeme Beardsmore: received his PhD from Monash University in Australia in 1996 for a thesis entitled “The Thermal History of the Browse Basin and its Implications for Petroleum Exploration.” This gave him a firm grounding in the spatial and temporal factors that affect subsurface temperature, and how to measure them. He was first exposed to the geothermal energy sector during a post-doctoral fellowship with world-renowned expert in the assessment of crustal temperatures and geothermal potential, and former President of the Geothermal Resources Council, Professor Dave Blackwell at Southern Methodist University in Dallas Texas in 1997/98. Returning to Monash University, he wrote “Crustal Heat Flow: A Guide to Measurement and Modelling”, which was published by Cambridge University Press in 2001 and remains the standard text on the topic.

Dr Beardsmore left Monash University in 2007 to become Technical Director of Hot Dry Rocks Pty Ltd (HDR), Australia’s only dedicated geothermal energy consultancy. Under his direction, HDR has developed software, laboratory instruments, exploration tools and methodologies to overcome exploration challenges in Australia and beyond.

Dr Beardsmore was elected to the Board of Directors of the International Geothermal Association (IGA) in 2007 and served two three-year terms. He remains Chairman of the IGA Resources and Reserves Committee, which is working to standardize the terminology, estimation and reporting of geothermal resources globally.

He continues to direct HDR activities, but also holds a position with National ICT Australia, where he works in a team developing open source software tools to quantify the probability of geothermal drilling success.

He recently worked with the IGA as assistant editor and author on a ‘Best Practices Guide For Geothermal Exploration’ commissioned by the International Finance Corporation. The first edition was launched in March 2013. A second, greatly expanded, edition is in press for imminent release. The guide introduces the concept of Geothermal Play Types and recommends specific exploration tools for each type of ‘play’.

With HDR, Dr Beardsmore has worked on projects that address real-world exploration and resource assessment issues in geothermal energy. These include writing the Australian Geothermal Reporting Code with the Australian Geothermal Energy Association (AGEA); developing Enhanced Geothermal Systems (EGS) mapping protocols with support from Google.org; developing (and retailing) laboratory equipment for thermal property measurements of rocks; developing a shallow heat flow measurement tool (currently on trial in Mexico); as well as assisting with many geothermal exploration projects across Australia and around the world. NICTA (National ICT Australia) is Australia’s Information and Communications Technology (ICT) Research Centre of Excellence and the nation’s largest organization dedicated to ICT research. NICTA’s research addresses technology challenges facing industries, communities and whole nations. NICTA’s primary goal is to pursue high-impact
research excellence and to be one of the world’s top ICT R&D centres. NICTA research teams have been independently ranked #1 in the world in ‘optimization’ and in the top 5 in the world in ‘machine learning’. From 2012-2014, Dr. Beardsmore worked with NICTA on a project to apply cutting edge machine learning and cloud computing techniques to geothermal exploration in Australia. The outcomes are relevant globally. NICTA also works on energy systems design optimization in the presence of uncertainty. This is very relevant for the planning and development of new energy infrastructure anywhere in the world.

**Alison Thompson:**
As one of Canada’s foremost champions of geothermal energy, Alison Thompson is paving the way for the Canadian energy sector to capitalize on a large, untapped resource of renewable energy. A Chemical Engineer with dual Master’s degrees in business administration and engineering, Ms. Thompson has dedicated a substantial part of her career to investigating and demonstrating the technical and commercial viability of high enthalpy geothermal energy.

From 2007-present, Ms. Thompson took the reins as Executive Director and remains as Chair of the Canadian Geothermal Energy Association (CanGEA), where she is building this non-profit organization into a respected and influential assembly of industry representatives advocating for the development and commercialization of Canada’s geothermal energy resources. In a country currently lacking a viable geothermal energy alternative, Ms. Thompson is ensuring that CanGEA raises awareness for geothermal energy as a competitive, emissions-free, renewable base-load energy. Working with policymakers at various levels to further bring to fruition legislation promoting geothermal energy development and a range of incentives, she continues to work tirelessly to unlock the resource and remove existing policy barriers and hurdles.

Ms. Thompson’s energy experience is diverse. She is currently the Chair and a Founder of the Canadian Geothermal Energy Association, the Chair of Borealis GeoPower and a board member of Deep Earth Energy Production. She was an Officer of Alterra Power (formerly Magma Energy), an external evaluator for the Canada Foundation for Innovation and has served on the Board of Directors of Petroleum Technology Alliance Canada. Internationally, she has a seat on the Executive Committee of the International Energy Agency’s Geothermal Implementing Agreement (IEA-GIA) and is a Board Member of the International Geothermal Association (IGA). She has also served on the European Union’s Enhanced Geothermal Innovative Network for Europe’s Stakeholders Committee and was the Geothermal Energy Forum Chair at the 20th World Petroleum Congress. She was recently the independent expert panel committee member tasked with a review of the geothermal research at the University of Alberta, which is a multi-year joint German (Helmholtz) and Alberta initiative. Ms. Thompson is also a board member of Youth Science Canada.

Ms. Thompson holds Bachelor and Master of Chemical Engineering degrees from McGill University, a Professional Engineering designation from APEGA, as well as a Master of Business Administration degree from Queen’s University.
Ashley Derry: received her Bachelor of Science with a combined degree in Earth and Ocean Sciences and Physics (Geophysics) from the University of Victoria in 2011. Upon graduating, she joined Borealis Geopower, a privately held Canadian geothermal power exploration and development company, as a geoscientist and has worked on numerous Canadian and international projects. Notably, she assisted in obtaining the first geothermal permit ever awarded in the Northwest Territories, and has been a part of the teams that have completed CanGEA’s Alberta and British Columbia Resource Estimate mapping projects. Ashley has also worked with CanGEA as their Operations Manager, helped spearhead their successful ‘powEARTHful Energy’ crowdfunding campaign in 2013, and has participated in the writing of many of their reports, including the Canadian Geothermal Technology Roadmap and their 2012 and 2013 Projects Overviews.

James L. Weimer: Mr. Weimer received both a Bachelor of Science and Master of Business and Administration from the University of British Columbia. He has 40 years of experience in financial management and 24 years as an independent consultant. Mr. Weimer has held various corporate positions for Mohawk Oil Co. Ltd. And MacMillan Bloedel Ltd, including Controller, Treasury Manager, and Senior Finance Manager. He is now an independent consultant for financial management, investment analysis, and business planning through his Vancouver based firm Weimer Consulting Inc. He has spent over 20 years advising small independents and large multi-nationals on the financial and economic evaluation of electrical power development. Many of his major client projects involve advising independent power developers in regulatory interventions and consultations with the utility on the economic and financial aspects of utility energy procurement and demand side management programs. Some of the District Energy Systems that he has advised include the City of Surrey’s City Centre District Energy Strategy, the University of Calgary’s West Campus Energy and Integrated Resource Management Study, and more recently the City of New Westminster’s Sapperton District Energy Feasibility Study. He has also consulted for Aeolis Wind Power Corporation, BC Hydro, ALTA Energy Corporation, Marine BioProducts Inc., among others. Mr. Weimer is a member of the Pacific Energy Association and the Clean Energy Association of BC.

T. M. Gunderson: T.M. has worked in the gas utility business and private pipeline and consulting business over the last 15 years. He brings years of experience in identifying opportunities in processes to generate clean power and renewable and thermal energy developments.

T.M. earned a CMA designation from CMA Alberta. He holds a M.Sc. degree in Science in Mechanical Engineering from the University of Alberta and is a registered Professional Engineer in Canada and the United States.
Appendix D: 2013 Updated BC Hydro RODAT Cost Data for Geothermal Projects

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<th>Project</th>
<th># Wells</th>
<th>GWOP ($CD)</th>
<th>GWOP ($USD)</th>
<th>Total Operating &amp; Maintenance ($CD)</th>
<th>Total Operating &amp; Maintenance ($USD)</th>
<th>LHI (Energy Cost of Fuel)</th>
<th>Annual Energy Cost of Fuel ($CD)</th>
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<td>Coquihalla Springs</td>
<td>14</td>
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</tr>
<tr>
<td>Mt. Edith</td>
<td>10</td>
<td>127,000</td>
<td>95,000</td>
<td>2,000</td>
<td>2,000</td>
<td>$1,600</td>
<td>$1,600</td>
<td>$1,280</td>
</tr>
<tr>
<td>Redve Motorcycle</td>
<td>10</td>
<td>175,000</td>
<td>130,000</td>
<td>2,500</td>
<td>2,500</td>
<td>$2,000</td>
<td>$2,000</td>
<td>$1,600</td>
</tr>
<tr>
<td>Lower Arrow Lake</td>
<td>20</td>
<td>375,000</td>
<td>280,000</td>
<td>4,000</td>
<td>4,000</td>
<td>$2,800</td>
<td>$2,800</td>
<td>$2,240</td>
</tr>
<tr>
<td>Aberdeen Valley</td>
<td>10</td>
<td>127,000</td>
<td>95,000</td>
<td>2,000</td>
<td>2,000</td>
<td>$1,600</td>
<td>$1,600</td>
<td>$1,280</td>
</tr>
</tbody>
</table>

Figure 18: Updated RODAT Cost Data for Geothermal Projects

Appendix E: Special Thanks to Contributors

Thank You to our Contributors for Making this Report Possible

Werner Antweiler
Philip Barton
Robert Charters
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Appendix F: Works Consulted


Dunn, Craig. “Geothermal site holds potential for future generations”. Canadian Mining Journal. (May 1, 2013).


National Renewable Energy Laboratory. “Geothermal Technologies Program:


Appendix G: Errata

December 8, 2014

As a result of recent developments, the following excerpt is provided as an addition to point 4 on page 9, and to supplant the last paragraph of section 2.1.4 on page 27:

In relation to this, deferring the upgrading of the existing transmission line from Prince George to the Terrace area, estimated at around $125 million, would also save BC Hydro a substantial sum of money. This could be done by supporting the development of the Lakelse Lake Geothermal Project in Terrace, BC.

Support of the Lakelse project would entail smaller amounts than the proposed $125 million for line upgrades, which would be required to ensure a sufficient flow of power to Terrace to support future industrial development in the region.

Similarly, the Terrace to Kitimat Transmission (TKT) Project could also be avoided. This line is primarily intended to provide energy for proposed LNG projects in the region. While no cost has yet been determined for this project, it could nonetheless be avoided by building a geothermal project in this area. The area is known to have considerable geothermal resources, and could save ratepayers a considerable sum.

Taken together then, geothermal energy has the potential to save ratepayers and BC Hydro substantial sums, as it would delay, or eliminate the need to build or upgrade various transmission lines. At the same time, geothermal energy projects would also have the added benefit of providing reliable energy to these areas, reducing the likelihood of brown-outs from being located at the end of transmission lines.
COMPARATIVE ANALYSIS OF GREENHOUSE GAS EMISSIONS OF SITE C versus ALTERNATIVES

July 2016
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This report was authored by Rick Hendriks (Camerado Energy Consulting), an energy consultant with 20 years experience in assessment and analysis of large-scale hydropower projects. The report was overseen by Dr. Karen Bakker (UBC), and independently reviewed by Dr. Arthur Fredeen (UNBC), Dr. Normand Mousseau (Université de Montreal), and Philip Raphals (Helios Centre, Montreal).
1. Summary

What and where is Site C? Site C is a hydroelectric dam on the Peace River currently in the early stages of construction. The site is located in northeastern British Columbia in the Peace Valley near Fort St John. Site C would be downstream from two other dams (including the Bennett Dam, one of the largest earth-filled dams in the world).

What is the key finding of the report? The Site C dam does not deliver energy and capacity at significantly lower greenhouse gas emissions than a fully optimized Alternative Portfolio put forward by BC Hydro (which includes wind energy). The difference in lifecycle GHG emissions, if a difference exists at all, is at most 1% of BC’s current emissions.

Why is this finding significant? Site C has more significant adverse environmental effects than any project ever reviewed under the history of the Canadian Environmental Assessment Act, including impacts on dozens of species, aquatics, vegetation, wildlife, Aboriginal use of lands and resources, and cultural heritage. The federal and provincial governments stated that the unprecedented level of significant adverse environmental effects from Site C are justifiable, in part, because the project delivers energy and capacity at substantially lower GHG emissions than the available alternatives. Our analysis indicates this is not the case.

How does this add to the analysis in the Joint Review Panel report? The Joint Review Panel (JRP) jointly commissioned by the federal and provincial governments did not analyze GHG emissions in detail. The JRP draws conclusions about the relative GHG emission advantages of the Site C Project without additional analysis beyond that provided by BC Hydro. Our analysis reviews the information presented by BC Hydro to the Joint Review Panel and also presents the findings of additional research concerning the GHG emissions of the Site C Project. The JRP noted in its report that its limited mandate and resources precluded analysis of some key issues. This report thus fills an important gap.

How was the analysis conducted? Optimizing the selection and operation of the resources composing the mostly likely Alternative Portfolio proposed by BC Hydro, the analysis indicates that the environmental assessment process for the Site C Project overlooked opportunities to reduce the average GHG emissions of the Alternative Portfolio from 611 to 68 kt CO$_2$e/year (a reduction of more than 0.5 Mt CO$_2$e/year) while maintaining costs. This reduces the average annual GHG emissions reduction benefits achieved by developing the Site C Project, compared to the Alternative Portfolio, to at most 0.1 Mt CO$_2$e/year. This is equivalent to just 0.15% of BC’s current emissions.
What about the timing of these emissions? The Site C Project entails the release of at least 4 Mt CO$_2$e emissions before 2035, as a result of construction-related emissions and the fact that reservoir emissions are concentrated in the early years following inundation. It will be several decades before the GHG emissions of an optimized Alternative Portfolio exceed those of the Site C Project, if ever. An optimized Alternative Portfolio has available to it all of the future technological advances that would allow for additional reductions in potential GHG emissions. This opportunity is unavailable to the Site C Project, since once it is constructed and operating, its GHG emissions are certain to occur. Fully optimizing the Alternative Portfolio would allow its emissions to remain below the emissions of the Site C Project indefinitely.

How do these emissions compare to other projects? The recently-approved Woodfibre LNG facility, even with its relatively low emissions intensity per tonne of LNG, is nearly 10 times the maximum annual GHG emission benefits of Site C compared to the optimized Alternative Portfolio. Were the Pacific Northwest LNG export facility to be approved, its annual emissions would be more than 120 times the maximum GHG emissions benefits of Site C, and would also represent over 95% of British Columbia’s 2050 emissions reduction target set out in the Clean Energy Act.

What about exporting energy from Site C to Alberta? It has been suggested that additional GHG emissions reductions would result from exporting surplus Site C energy to Alberta. The purpose of the Site C Project, as proposed by BC Hydro, was to meet British Columbia’s domestic electricity requirements; Site C was not evaluated in an export context. This report questions the potential for exporting Site C energy to Alberta, as the cost of Site C energy is high compared to other renewables such as wind and solar. Our analysis indicates that these other renewables could be much better alternatives for replacing coal, helping Canada achieve its climate change goals more quickly and affordably, and with much lower overall environment impact compared to Site C.

Need for comprehensive review: The findings of our research reinforce the statements of the Joint Review Panel, which indicated that it had insufficient time and resources to conduct a full assessment of the Site C Project. Our analysis also supports the recommendation of the Joint Review Panel for a more thorough review by the BC Utilities Commission prior to any decision to proceed with development at Site C.
2. Regulatory and policy context

BC Hydro’s planning environment in terms of greenhouse gas (GHG) emissions is set out in the requirements of the *Clean Energy Act*, including as follows:

- 2(c) to generate at least 93% of the electricity in British Columbia, other than electricity to serve demand from facilities that liquefy natural gas for export by ship,\(^1\) from clean or renewable resources and to build the infrastructure necessary to transmit that electricity;
- 2(f) to ensure the authority’s rates remain among the most competitive of rates charged by public utilities in North America;
- 2(h) to encourage the switching from one kind of energy source or use to another that decreases greenhouse gas emissions in British Columbia;
- 2(n) to be a net exporter of electricity from clean or renewable resources with the intention of benefiting all British Columbians and reducing greenhouse gas emissions in regions in which British Columbia trades electricity while protecting the interests of persons who receive or may receive service in British Columbia; and
- 6(2) (b) relying on Burrard Thermal for no energy and no capacity, except as authorized by regulation.

The alternative portfolios developed and assessed by BC Hydro in its 2013 Integrated Resource Plan (IRP) for meeting the requirements for firm energy and dependable capacity all comply with the above requirements, including the requirement that 93% of BC’s electricity come from clean resources. As a result, all of the alternative portfolios produce low levels of GHG emissions.

In its 2013 IRP, BC Hydro reported the detailed GHG emissions related only to fuel combustion during operations of the Site C Project, while excluding emissions related to its construction and reservoir inundation.\(^2\) As a result, in the IRP, the utility reported GHG emissions of Site C as “no direct emissions”.\(^3\) In its Environmental Impact Statement (EIS) for the Site C Project, BC Hydro prepared a more detailed assessment of the GHG emissions for Site C construction and reservoir operations,\(^4\)\(^5\) reporting lifecycle emissions of 3.7 to 8.5 Mt CO\(_2\)e (see Table 1). It also provided emission rates

---

\(^{1}\) As per British Columbia’s Energy Objectives Regulation (B.C. Reg. 234/2012).


www.watergovernance.ca www.siteCstatement.org
for the electricity generation resources used in the alternative portfolios, discussed below.

During the Site C Joint Review Panel (JRP) hearings, minimal attention was paid to the issue of GHG emissions. Over the course of the 25 days of hearings, the JRP dedicated one afternoon session to atmospheric and air quality issues, of which the sub-topic of GHG emissions was one of five sub-topics. No evidence concerning GHG emissions was presented to the Panel during the hearings, other than by BC Hydro. The JRP undertook no independent analysis of the findings of BC Hydro, and solicited no additional evidence through undertakings by BC Hydro or other interveners. Yet, the JRP reached the following conclusion in its final report to the Ministers:

[Site C] would produce a vastly smaller burden of greenhouse gases than any alternative save nuclear power, which B.C. has prohibited. [emphasis added]

Our analysis, presented below, demonstrates that this finding of the JRP, based as it was on limited evidence was, in fact, unfounded. This uncritical view of the GHG emissions of the Site C Project, as compared to the available alternatives identified by BC Hydro in its 2013 IRP, is shared by many, including the Provincial Minister of Energy and Mines, who recently stated the following:

“The hydroelectric project will deliver the lowest-cost, cleanest power available,”
the minister said, although he conceded it would have adverse environmental impacts downstream.

It is this concession by the Minister that reveals the underlying process used by government to justify approving the Site C Project: the significant environmental effects of the Site C Project, which are unprecedented, are justifiable because the project is presumed to deliver energy and capacity at lower costs and lower GHG emissions (i.e. the “cleanest”) compared to the available alternatives.

The chair of the Joint Review Panel, Dr. Harry Swain, has recently stated that, in his view, this justification test has not been satisfied:

The environmental and First Nations land rights issues are serious costs that would have to be borne if the [Site C] project goes ahead. You would only want to do that if there were an overwhelming economic case that this was the best and cheapest way, including all external effects, of providing something that the

---

9 Briefing Note #2 Assessing Alternatives to Site C: Environmental Effects Comparison. Available at: www.siteCstatement.org.
provincial economy absolutely required. And I'm saying since you can't pass that test then the rest of it is moot.”

This is, indeed, a key issue. This report provides independent comparative analysis of GHG emissions in order to inform this debate.

3. Presentation of estimations of greenhouse gas emissions

3.1 Estimations of greenhouse gas emissions from Site C

As explained in the EIS, the GHG emissions from the Site C Project are not nil, but include construction-related emissions, life-cycle emissions from manufacturing, and reservoir-related emissions.

In preparing its emissions estimate in the EIS, BC Hydro considered both “likely” (lower emission) and “conservative” (higher emission) scenarios. During construction, the conservative scenario assumes 15% greater fuel emissions and greater life-cycle emissions for construction materials than in the likely scenario. For operations, the conservative scenario assumes no storage of carbon and no burial of biomass, while the likely scenario assumes that merchantable timber inundated by the reservoir will be converted entirely into stored carbon (i.e. as building materials for the construction industry) and that 30% of non-merchantable timber cleared from the reservoir would be buried (and therefore indefinitely stored). During the operations phase, both estimates assume that the reservoir emissions occur almost entirely in the early years following inundation, and eventually decline to resemble those prior to reservoir creation. In order to assess the uncertainty of these estimates, BC Hydro also undertook a sensitivity analysis of various input parameters in order to develop “minimum likely” and “maximum conservative” estimates.

The resulting total Site C GHG emissions, including construction-related emissions, for the 108-year construction and operation period are summarized below in Table 1. These data do not tell the full story, however, as Site C’s GHG emissions are heavily front-loaded.

Table 1. Range of Site C Project GHG Cumulative Emissions Estimates

<table>
<thead>
<tr>
<th></th>
<th>Minimum (kt CO₂e)</th>
<th>Likely (kt CO₂e)</th>
<th>Conservative (kt CO₂e)</th>
<th>Maximum (kt CO₂e)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Operations</td>
<td>2,713</td>
<td>4,344</td>
<td>5,825</td>
<td>6,970</td>
</tr>
<tr>
<td>Construction - Materials</td>
<td>628</td>
<td>628</td>
<td>1,060</td>
<td>1,060</td>
</tr>
<tr>
<td>Construction - Fuel</td>
<td>363</td>
<td>363</td>
<td>417</td>
<td>417</td>
</tr>
<tr>
<td>Construction - Electricity</td>
<td>6</td>
<td>6</td>
<td>7</td>
<td>7</td>
</tr>
<tr>
<td>TOTAL</td>
<td>3,710</td>
<td>5,341</td>
<td>7,309</td>
<td>8,454</td>
</tr>
<tr>
<td>Annual average (over 108 years)</td>
<td>34.4</td>
<td>49.5</td>
<td>67.7</td>
<td>78.3</td>
</tr>
</tbody>
</table>

11 GHG Report, supra note 5, p.84.
12 Ibid., p.54.
13 Ibid., p.92.
14 Ibid., Table 10.2, p.108.
15 CO₂ equivalents (CO₂e) calculated on a 100-year global warming potential of 21 for CH₄ and 310 for N₂O.
Figure 1 demonstrates that the Site C Project would produce annual emissions of 500 to 1000 kt/year CO$_2$e during the period 2024-2030 – a critical period for emissions reductions if Canada is to meet its commitments to reduce GHG emissions by 30% below 2005 levels by 2030.  As demonstrated below in section 4.5, the Alternative Portfolio avoids this emissions spike.

**Figure 1**

3.2 Estimations of greenhouse gas emissions from Alternative Portfolios

In its IRP and in its EIS for the Site C Project, BC Hydro compared three alternative portfolios of resources for meeting the needs for electrical energy and dependable capacity in terms of GHG emissions. These portfolios all make up approximately the same 5,100 GWh of annual energy and 1,100 MW of dependable capacity as the Site C Project, as shown in Table 2.

---


17 GHG Report, supra note 5, Table C.4 and Table C.6.
Table 2. BC Hydro’s Integrated Resource Plan Portfolios

<table>
<thead>
<tr>
<th>Portfolios</th>
<th>Clean</th>
<th>Clean + Thermal #1</th>
<th>Clean + Thermal #2</th>
<th>Site C</th>
</tr>
</thead>
<tbody>
<tr>
<td>Supply-side Resources</td>
<td>Dependable Capacity MW</td>
<td>Annual Energy GWh/year</td>
<td>Dependable Capacity MW</td>
<td>Annual Energy GWh/year</td>
</tr>
<tr>
<td>Site C</td>
<td>1244</td>
<td>5100</td>
<td>1112</td>
<td>5101</td>
</tr>
<tr>
<td>GM Shrum</td>
<td>220</td>
<td>0</td>
<td>220</td>
<td>0</td>
</tr>
<tr>
<td>Revelstoke 6</td>
<td>468</td>
<td>26</td>
<td>488</td>
<td>26</td>
</tr>
<tr>
<td>Municipal Solid Waste</td>
<td>36</td>
<td>312</td>
<td>36</td>
<td>312</td>
</tr>
<tr>
<td>Natural Gas (SGT)</td>
<td>500</td>
<td>364</td>
<td>588</td>
<td>924</td>
</tr>
<tr>
<td>Pumped Storage</td>
<td>5326</td>
<td>3829</td>
<td>3829</td>
<td>3829</td>
</tr>
<tr>
<td>Wind</td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Totals</td>
<td>1244</td>
<td>5100</td>
<td>1112</td>
<td>5101</td>
</tr>
</tbody>
</table>

The resources included in these portfolios consist of available resources for meeting the needs within regulatory, planning and technical constraints, including the provincial energy objectives in the *Clean Energy Act*.

- Clean portfolio – wind resources for energy, additional capacity at Revelstoke 6, capacity upgrades at G.M. Shrum, municipal solid waste generation, and pumped storage hydro
- Clean + Thermal #1 – wind resources for energy, Revelstoke 6, municipal solid waste generation, and natural gas generation (6 simple cycle gas turbines (SCGTs))
- Clean + Thermal #2 – wind resources for energy, Revelstoke 6, G.M. Shrum, municipal solid waste generation and natural gas generation (4 SCGTs)
- The Site C Project for an in-service date of F2024

The objectives of the *Clean Energy Act*, discussed in section 4.1, include that BC Hydro’s rates “remain among the most competitive of rates charged by public utilities in North America.” As such, the comparative costs of the portfolios are also relevant to the consideration of the justification of environmental effects. The following table illustrates the present value (PV) cost differences determined by BC Hydro in its IRP, for Site C commissioning in F2024.

---

19 *Clean Energy Act*, SBC 2010, c22, s.2(f).
Table 3. Portfolio present value for Site C base case analysis

<table>
<thead>
<tr>
<th>Portfolio Type</th>
<th>Portfolios without Site C Portfolio PV (M$)</th>
<th>Portfolios with Site C Portfolio PV (M$)</th>
<th>PV Difference (M$) (Portfolio without Site C minus Portfolio with Site C)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Clean</td>
<td>6,766</td>
<td>6,138</td>
<td>630</td>
</tr>
<tr>
<td>Clean + Thermal</td>
<td>6,030</td>
<td>5,883</td>
<td>150</td>
</tr>
</tbody>
</table>

Some observations:

- Developing all clean generation without Site C was found to be about $700 million more expensive than similar portfolios with some thermal generation (i.e. natural gas), as a result of the need to advance costly pumped storage hydro;
- The benefit of Site C compared to the clean + thermal alternative was just $150 million, which represented 1.7% of the estimated cost of Site C of $8.8 billion at the time of sanction.

The Clean + Thermal portfolios therefore provide the most likely alternatives to the Site C Project, while still meeting the requirements of the Clean Energy Act, including with respect to GHG emissions and competitive electricity rates.

The most recent project cost estimate for Site C is a Class 2 cost estimate as defined by AACE International, which means that the expected accuracy range in the estimate is -5% to +5%.21,22 The resources composing the Clean + Thermal portfolios are developed to the feasibility level in the case of capacity upgrades at Revelstoke, the pre-feasibility level for wind, MSW generation and natural gas, and the concept level in the case of capacity upgrades at GM Shrum.23 This is equivalent to a Class 4 cost estimate for the entire portfolio, and therefore has an expected accuracy range of -15% to +20%. In other words, the perceived economic benefit of Site C over the Clean + Thermal Portfolios is less than the margin of error in the Site C cost estimate, and much less than the margin of error in the estimate of the Clean + Thermal Portfolios. This demonstrates the importance of the recommendation by the JRP that the Site C cost estimate be reviewed by the BC Utilities Commission.24

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20 IRP, supra note 2, Appendix 6A Portfolio Results, p.6A-36.
23 IRP, supra note 2, Appendix 3A-4: 2013 Resource Options Report Update Resources Options Database (RODAT) Summary Sheets.
24 JRP Report, supra note 7, p.280.
Of potential concern, in light of the requirements under the *Clean Energy Act*, is that some of the resources in the Clean + Thermal portfolios, including MSW generation and SCGTs, emit carbon dioxide. Though technology for separating CO₂ from facility exhaust is available, it is costly and untested in BC,²⁵ and it is unlikely that CO₂ removal technology would be employed for an SCGT considering its relatively small size and limited hours of operation. In addition, these combustion resources, as well as wind generation resources, which play a prominent role in the alternative portfolios, also produce life-cycle GHG emissions as a result of construction activities and materials manufacture.

In its IRP, BC Hydro determined GHG emission rates (in CO₂e/GWh) specific to each supply-side resource, based on direct emissions from fuel combustion.²⁶ These estimates excluded emissions from other phases of the resource life cycle, including construction, land clearing, emissions embedded in materials, etc. BC Hydro noted that these life cycle emissions are “generally small in comparison to emissions from fuel combustion at a power plant”.²⁷ In the EIS, however, BC Hydro also reported figures for life-cycle emissions, including those related to construction and materials. Table 4 below summarizes the direct GHG emissions from fuel combustion and the life cycle GHG emissions for the various alternative resources. It is striking to note that the value provided in the IRP for GHG emissions from MSW is even greater than that from natural gas generation.

**Table 4. Emissions intensity for alternative generation sources**

<table>
<thead>
<tr>
<th>Electricity Resource</th>
<th>IRP²⁶ Combustion Emissions (t CO₂e/GWh)</th>
<th>EIS Lifecycle Emissions Range²⁹ (t CO₂e/GWh)</th>
<th>EIS Lifecycle Emissions Average³⁰,³¹ (t CO₂e/GWh)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Diesel</td>
<td>--</td>
<td>555 – 880</td>
<td>717</td>
</tr>
<tr>
<td>Municipal Solid Waste (MSW)</td>
<td>694</td>
<td>694²⁷</td>
<td>694</td>
</tr>
<tr>
<td>Natural Gas (SCGTs)</td>
<td>477</td>
<td>469 – 622</td>
<td>545</td>
</tr>
<tr>
<td>Solar Photovoltaic</td>
<td>--</td>
<td>13 – 104</td>
<td>58</td>
</tr>
<tr>
<td>Wind</td>
<td>0</td>
<td>7 – 22</td>
<td>14</td>
</tr>
</tbody>
</table>

The GHG emissions from SCGTs depend not only upon their operating hours, but also on the frequency of start-ups and shutdowns. BC Hydro did not present information in

²⁹ *GHG Report, supra* note 5, p.106.
³¹ Average refers to the 100-year average.
³² The EIS did not provide additional information, so the IRP values are used.
its EIS or its IRP concerning the frequency of start-ups and shutdowns of the SCGTs proposed for the Alternative Portfolio. In a recent submission to the California Energy Commission in relation to the proposed Alamitos Energy Center, the emissions of SCGTs identical to those proposed by BC Hydro were determined to be 633 t CO₂e /GWh, including start-ups, shutdowns and performance degradation over time.  

This value is higher than the 545 t CO₂e /GWh presented by BC Hydro in its EIS and as stated in Table 4 above. This results from the higher frequency of start-ups and shutdowns (500 per year, or 1 per every 4 hours of operations) and different assumptions concerning global warming potential, emission factors, thermal efficiencies, performance degradation and other input variables. For example, presuming that BC Hydro operates the facilities 16-hours per day during the winter cold snaps as proposed, the number of start-ups and shutdowns would be 1 per every 16 hours of operations, far fewer than the 1 per 4 hours of operations used in the analysis of the Alamitos Energy Center. This lower frequency of start-up and shutdown cycles lowers the average GHG emissions found in the case of the Alamitos Energy Center from 633 to 593 t CO₂e /GWh.

Lacking detailed operational information for the SCGTs proposed in the Alternative Portfolio, and the full slate of assumptions underlying BC Hydro’s determination of the GHG emissions intensity for SCGTs, the analyses in this briefing note utilize the 545 t CO₂e/GWh presented by BC Hydro in its EIS. Referral of the Site C Project to the BC Utilities Commission would allow for further exploration of these matters. 

Table 5 summarizes the GHG emissions for the “Clean + Thermal #2” portfolio in the 2013 IRP (the “Alternative Portfolio”), based on the emissions intensities in Table 4. As Table 5 illustrates, BC Hydro determined the emissions of the Alternative Portfolio to be 511 kt CO₂e/year in its IRP considering only combustion during operations. Considering life-cycle emissions, based on emissions intensities reported in the EIS, this total increases to 611 kt CO₂e/year. For context, a typical natural gas combined cycle generating turbine operating to produce 5,100 GWh/year would emit more than four times as much (2,780 kt CO₂e/year).

Indeed, the Alternative Portfolio produces much lower emissions than an “all gas” alternative to the Site C Project. Nevertheless emissions still exceed those of the Site C Project by about 500 kt or 0.5 Mt CO₂e/year. However, the analyses presented by BC Hydro in the IRP and the EIS did not seek to minimize the GHG emissions in the Alternative Portfolio by optimizing the selection and operation of the available resources. Further optimization is readily available, and the proposed approaches below focus on further lowering the emissions of the Alternative Portfolio without increasing its costs.

33 GE Power LMS100 gas turbines.
35 Ibid.
### Table 5. GHG Emissions – Alternative Portfolio

<table>
<thead>
<tr>
<th>Resources</th>
<th>Annual Generation 36</th>
<th>GHG Combustion Emissions Intensity</th>
<th>GHG Combustion Emissions</th>
<th>GHG Lifecycle Emissions Intensity</th>
<th>GHG Lifecycle Emissions</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>(GWh/year)</td>
<td>(t CO(^2)e/GWh)</td>
<td>(kt CO(^2)e/year)</td>
<td>(t CO(^2)e/GWh)</td>
<td>(kt CO(^2)e/year)</td>
</tr>
<tr>
<td>GM Shrum(^{37})</td>
<td>0</td>
<td>0</td>
<td>0</td>
<td>0</td>
<td>0</td>
</tr>
<tr>
<td>Revelstoke 6</td>
<td>26</td>
<td>0</td>
<td>0</td>
<td>0</td>
<td>0</td>
</tr>
<tr>
<td>MSW(^{38})</td>
<td>312</td>
<td>694</td>
<td>217</td>
<td>694</td>
<td>217</td>
</tr>
<tr>
<td>Natural Gas</td>
<td>616</td>
<td>477</td>
<td>294</td>
<td>545</td>
<td>336</td>
</tr>
<tr>
<td>Wind(^{39})</td>
<td>4148</td>
<td>0</td>
<td>0</td>
<td>14</td>
<td>58</td>
</tr>
<tr>
<td>Totals</td>
<td>5102</td>
<td>511</td>
<td>611</td>
<td></td>
<td></td>
</tr>
</tbody>
</table>

36 *IRP, supra* note 2, Chapter 6 Resource Planning Analysis, Table 6-9, p.6-39.
37 Lifecycle GHG emissions for capacity upgrades at GM Shrum and Revelstoke 6 are unavailable and presumed to be zero for comparison purposes. Eventual turbine replacement at the Site C Project is also presumed to have no GHG emissions.
38 Lifecycle GHG emissions for MSW generation other than in relation to combustion are unavailable and presumed to be zero for comparison purposes.
39 *EIS, supra* note 4, Volume 2, Section 15: Greenhouse Gases, Table 15.11 Emissions Intensity – Project Compared with other Generation.
4. Optimizing the resources in the Alternative Portfolio

4.1 Replacing MSW generation with SCGTs and wind

In its analysis, BC Hydro makes use of MSW generation as part of the Alternative Portfolio. MSW generation involves the incineration of municipal solid waste to produce electricity, following pre-processing of waste to remove oversized, non-combustible, hazardous or explosive materials. MSW generation is generally promoted by the province as part of a strategy to manage municipal solid waste in British Columbia.\(^{40}\)

Though MSW generation is a “clean” resource in the *Clean Energy Act*, it actually produces very high GHG emissions (694 t CO\(_2\)e/GWh), on par with diesel generation (717 t CO\(_2\)e/GWh). Replacing the MSW generation resource from the Alternative Portfolio with a combination of SCGTs and wind can provide the capacity and energy of MSW generation while producing much lower GHG emissions at comparable cost.\(^{41}\)

More specifically, replacing the 37 MW of dependable capacity and 312 GWh/year of firm energy provided by the MSW generation with additional SCGTs and wind in the Alternative Portfolio reduces its GHG emissions by 182 kt CO\(_2\)e/year. This reduction occurs because the emissions intensity of a combination of wind and natural gas is much lower than the emissions intensity of MSW generation.

4.2 Optimizing the operations of simple-cycle gas turbines (SCGTs)

The *Clean Energy Act* establishes that at least 93% of the electricity in British Columbia must come from clean (i.e. non-greenhouse gas emitting) or renewable resources. Currently, high-GHG resources account for some 6% of BC Hydro’s electricity supply, leaving a “GHG headroom” of around 500 GWh/year available for non-clean resources.\(^{42}\) In its IRP, BC Hydro concluded that the best strategy is to reserve the GHG headroom as a capacity and contingency resource, particularly in the event of rapidly increasing electricity requirements resulting from LNG development.\(^{43}\)

In its analysis, BC Hydro assumes that a typical 100 MW SCGT would produce 154 GWh of energy per year, and associated GHG emissions. This implies that SCGTs, which are acquired as capacity resources for peaking purposes, would operate 18% of the time, or 1577 hours per year. This is the equivalent of operating 16 hours a day, 6 days a week, for four months a year. The effect of this assumption is not inconsequential, as the greater the annual hours of operation, the greater the annual emissions. The GHG emissions of SCGTs depend upon both their hours of service and on the frequency of start-ups and shutdowns.


\(^{41}\) For a list of resource costs see: IRP, *supra* note 2, Appendix 6A, p. 6A-27.

\(^{42}\) 3500 GWh/year from Fort Nelson, Prince Rupert, McMahon Cogen and the Island Generation Plant. IRP, *supra* note 2, Chapter 6 Resource Planning Analysis, p.6-10.

BC Hydro notes that its capacity resources must be available to operate during “a 16-hour block per day for a two week cold snap that can happen at least three times per year anytime during the winter.” Typically, cold snaps occur once or twice during the critical winter period between November and February. BC Hydro also clarifies that the heavy load hours during a winter peak exclude Sundays and statutory holidays.

The BC Hydro analysis confuses the hours that the SCGTs need to be available to operate (i.e. the daily peak hours during the critical winter period) with the hours that the SCGTs will be called upon to operate, which will be much fewer. If there are three two-week cold snaps (or ~35 heavy load days, excluding Sundays and holidays) during the critical winter period, with the SCGTs operating 16 hours each of those days, they would operate for 560 hours per year, for a capacity factor of 6.4% (about a third of the service hours assumed by BC Hydro). This is consistent with the findings of the U.S. Energy Information Administration, which concluded that the average annual capacity factor, for each of the past 8 years, of all SCGTs in operation in the United States ranged from 4.5% to 6.7%. The actual number of hours that BC Hydro would operate any SCGTs during a cold snap would sometimes be less than 16 hours each day, and the average annual number of cold snaps would be fewer than the three assumed in this estimate, based on historical patterns.

In summary, BC Hydro’s assumption of a high capacity factor for SCGTs penalizes the Alternative Portfolio by overstating its annual GHG emissions. Assuming operation of the SCGTs at a 5% capacity factor in a manner consistent with industry practice and with the stated frequency and duration of cold snaps, accounting for the reduced energy production from the SCGTs with additional wind resources, and adding in the life-cycle GHG emissions from these wind resources, would reduce GHG emissions in the Alternative Portfolio by 236 kt CO₂e/year.

4.3 Developing capacity-focused DSM to offset or replace SCGTs

While most DSM programs do reduce capacity as well as energy requirements, until recently reducing capacity requirements has not been the primary focus in DSM program design. Programs designed specifically to reduce capacity requirements are referred to as “capacity-focused DSM”.

Assumptions made in approving the Site C Project

In the load resource balance presented in its 2013 IRP, BC Hydro identified a need for capacity by F2019, at least five years before a need for energy. In the 2016 load

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44 BC Hydro. 2015. BC Hydro 2015 Rate Design Application [‘RDA’], Appendix C-5A, p.96.
46 Ibid., p.46.
In response to this future need, and recognizing the prioritization of DSM in the *Clean Energy Act*, BC Hydro identified two types of capacity-focused DSM with substantial potential:

- **Industrial load curtailment:** 382 MW of expected capacity savings from large customers who agree to curtail load on short notice to provide BC Hydro with capacity relief during peak periods; and
- **Capacity-focused programs:** 193 MW in expected capacity savings from programs that leverage equipment (e.g. water heaters, heating, lighting and air conditioning) and load management systems to enable peak load reductions to occur automatically or with intervention through direct load control.

As a result, the potential for capacity-focused DSM savings identified in the IRP total 575 MW – over 50% of the capacity of Site C, and over 140% of the capacity of the SCGTs in the Alternative Portfolio. However, noting the uncertainty in the potential quantity of capacity-focused DSM savings actually achievable, BC Hydro elected to “not yet rely on capacity savings from capacity-focused DSM for resource planning purposes.” Instead, in the face of this short-term uncertainty respecting the contribution of capacity-focused DSM, BC Hydro assumed that for long-term planning purposes these options would make no contribution to the utility’s capacity needs and would deliver 0 MW over the next 20 years.

The utility recommended further study of capacity-focused DSM as one of the recommendations of the 2013 IRP. As called for in Recommended Action #2, BC Hydro completed a pilot study of automated demand response and direct load control, both effective forms of capacity-focused DSM. The study identified a potential of 53 MW of reliable winter capacity reduction in the Kamloops area alone. This result exceeded by far the 30 MW target set by BC Hydro for this region, which represents approximately 10% of the Provincial industrial electricity demand – implying a province-wide potential on the order of 500 MW. BC Hydro is continuing with these and other pilot programs.

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50 *IRP, supra* note 2, Chapter 3 Resource Options, p.3-22. In its 2012 Draft IRP, BC Hydro had also proposed a third option, time-of-use (TOU) rates, but it abandoned this approach – at the same time as it launched a province-wide smart-meter program, which for the first time made broad-based TOU rates a realistic option.
52 Enbala Power Networks. Undated. Capacity Focused Demand Side Management at BC Hydro: Industrial and Commercial Potential in the Kamloops Region.
53 The study was based on a 4-hour curtailment period, but BC Hydro also has up to 16-hour requirements to meet shoulder capacity needs.
New information since the approval of the Site C Project

Despite its decision not to include any capacity-focused DSM in its 2013 IRP, BC Hydro stated the following in its recently filed 2015 Rate Design Application (RDA):

In BC Hydro’s view, load curtailment potentially offers a better avenue [than time of use pricing (TOU)] to avoid costly generation capacity resource additions because it is targeted at capacity, is more reliable (particular with aspects of demand control), and in contrast to TOU, load curtailment is dispatchable.

…the 2013 IRP identifies that 400 MW of SCGTs would be required by F2020 if LNG projects proceed. There is an opportunity to reduce the amount of gas-fired generation that might be required through the development of load curtailment.55 [emphasis added]

In other words, BC Hydro now acknowledges the substantial benefits of load curtailment to reduce the 400 MW of SCGTs required in the event that LNG projects proceed, and yet no similar consideration was given in the 2013 IRP to utilizing load curtailment to reduce the 400 MW of SCGTs in the Alternative Portfolio. While the RDA does not yet quantify the magnitude of the capacity reduction resulting from load curtailment, it is clearly anticipated to be more than the 0 MW presumed in the IRP.

If capacity-focused DSM had been given appropriate consideration in the 2013 IRP, it would have contributed to deferring for several years the need for the Site C Project, a very costly capacity resource addition.56 Based on the recent information in the 2016 load resource balance update, over the coming decade each 100 MW of capacity-focused DSM delays the need for new resources by one year in the “Expected LNG” scenario57 and by more than two years in a scenario where LNG does not materialize.58

Experience in neighbouring jurisdictions

In its RDA, BC Hydro also undertook a jurisdictional review of load curtailment programs at winter-peaking Canadian utilities. The review reported that all of these programs were optional, and that most of the programs had maximum curtailment durations of 4 hours.59 No information concerning success of these Canadian programs was provided in the RDA. In addition, no similar review was undertaken for winter-peaking American utilities, many of which have been employing capacity-focused DSM (also known as “demand response”) for many years. According to the US Energy Information

56 In the environmental assessment hearings, unrebutted evidence was presented before the JRP to the effect that, as long as the Site C Project’s energy production is surplus to BC’s needs, the unit capacity cost of the project is between $150 and $350/kW-year – far more expensive than other capacity resources, including those listed in IRP, supra note 2, Appendix 6A, p. 6A-27. See Raphals, P. January 18, 2014. Response to BC Hydro Rebuttal Evidence (CEAR #63919-2548), p.9.
57 BC Hydro estimated that future requirements of the LNG industry could range from 800 to 6,600 GWh/year (100 to 800 MW) with an Expected LNG load of 3,000 GWh/year and 360 MW by F2022.
Administration, peak capacity savings (winter and summer) from demand response in the U.S. totalled 12,700 MW in 2014, and these numbers are expected to increase considerably in the coming years.\(^60\) In the PJM Interconnection alone, 2,500 MW of winter demand response was called into action during certain critical hours in January 2014.\(^61\)

Since the approval of the Site C Project in December 2014, the Northwest Power and Conservation Council (NPCC) released its Seventh Northwest Conservation and Electric Power Plan.\(^62\) NPCC issues its 20-year plan every five years for the states of the Pacific Northwest. This region consists of both public and investor-owned utilities that collectively comprise an electrical system that is about three times the size of BC Hydro’s integrated system, but is similar in demand profile (winter peaking) and resource mix (substantial hydroelectric resources).

Like BC Hydro, the NPCC assesses demand response primarily for the purpose of reducing peak load and, specifically, for deferring the development of new generation and transmission assets. In relation to winter demand response potential, which is most relevant to BC Hydro, the NPCC identified approximately 3,500 MW of regional winter demand response potential over the 20-year planning period. Nearly 1,500 MW is available at less than $32 per kilowatt of peak capacity per year (kW-year), and an additional 1,200 MW at less than $71 per kW-year.\(^63\) This 2,700 MW represents approximately 6% of winter peak load in the Pacific Northwest. Several utilities in the Pacific Northwest are now implementing winter demand response, including PacifiCorp (149 MW), Portland General Electric (28 MW), and the Bonneville Power Administration (60 MW).\(^64\)

BC Hydro estimated the cost of its capacity-focused DSM programs at $69 per kW-year,\(^65\) similar to that determined by the NPCC for the Pacific Northwest. In BC, 6% of winter peak capacity would be equivalent to about 700 MW of demand response potential. This provides further indication that the magnitude of potential demand response savings is much greater than the 0 MW presumed in the IRP.

\textit{Integrating capacity-focused DSM in the alternative portfolio}

Including the additional capacity from SCGTs used to replace MSW generation noted above in Table 2, the Alternative Portfolio would have 436 MW of SCGTs. Developing about 40% of the 575 MW of potential capacity savings from the capacity-focused DSM measures identified in the IRP would offset half of the SCGT capacity contemplated in

\hspace*{1cm}\\footnotesize{\textsuperscript{60} U.S. Energy Information Administration. 2016. Today in Energy: Demand response saves electricity during times of high demand. Available at: \url{http://www.eia.gov/todayinenergy/detail.cfm?id=24872}. \hspace*{1cm}}

\hspace*{1cm}\\footnotesize{\textsuperscript{61} FERC. December 2014. Assessment of Demand Response and Advance Metering (staff report), p.12. Available at: \url{http://www.ferc.gov/legal/staff-reports/2014/demand-response.pdf}. \hspace*{1cm}}

\hspace*{1cm}\\footnotesize{\textsuperscript{62} Northwest Power and Conservation Council. 2016. Seventh Northwest Conservation and Electric Power Plan. Available at: \url{http://www.nwcouncil.org/energy/powerplan/7/plan/}. \hspace*{1cm}}

\hspace*{1cm}\\footnotesize{\textsuperscript{63} \textit{Ibid.}, Table 14-2. (values converted to Canadian dollars). \hspace*{1cm}}

\hspace*{1cm}\\footnotesize{\textsuperscript{64} \textit{Ibid.}, Table 9-1. \hspace*{1cm}}

\hspace*{1cm}\\footnotesize{\textsuperscript{65} \textit{IRP, supra} note 2, Chapter 3 Resource Options, Table 3-6, p.3-28. \hspace*{1cm}}
the Alternative Portfolio. Developing 80% of the potential capacity savings from these capacity-focused DSM measures (supplemented as required with energy storage, as described below) would offset all of the SCGT capacity in the Alternative Portfolio. With SCGTs operated at a 5% capacity factor, these two levels of capacity-focused DSM would result in net annual GHG emissions from the Alternative Portfolio of 119 kt CO₂e/year and 68 kt CO₂e/year, respectively (see Table 6).

Though capacity-focused DSM is reliable and dispatchable, relying on it to replace most or all of the contemplated SCGTs raises complex questions best explored through a review before the BC Utilities Commission. First, though BC Hydro’s load curtailment and capacity-focused DSM programs show promise and are anticipated to provide much more than the 0 MW presumed in the IRP, they remain at the pilot phase, with the ultimate effectiveness of the measures to be determined over the next few years. Second, in addition to requiring peak capacity, the BC Hydro system becomes energy constrained in the shoulder hours before and after the peak period on winter days during a cold snap. This means that the capacity resources must at times be available for up to 16-hour periods, which is longer than the 4-hour period typical of load curtailment and capacity-focused DSM programs in other jurisdictions.

These uncertainties may – or may not – limit the extent to which capacity-focused DSM can offset the operation or requirements for SCGTs. If necessary, capacity-focused DSM can also be supplemented with energy storage technologies, which are fast becoming a viable resource in electricity systems across North America. Though costs remain high, they continue to decline rapidly. 66 Ontario recently procured 33.5 MW of energy storage and is proceeding with additional procurement to a total of 50 MW. 67 Of particular interest in the current context, San Diego Gas & Electric recently contracted for both a 20 MW lithium ion battery energy storage facility and 18.5 MW of DSM capacity savings. 68 Considering that the need for SCGTs in the Alternative Portfolio does not arise until F2027, BC Hydro has ten years to benefit from additional declines in the costs of battery and other energy storage, improving the prospects that the Alternative Portfolio could proceed with very limited, if any, use of SCGTs.

### 4.4 Summary

The above discussion illustrates several approaches available for optimizing the GHG emissions from the Alternative Portfolio. The resulting GHG emissions for each of these approaches are summarized in Table 6, along with the values presented previously in Table 5. This analysis indicates that the environmental assessment process for the Site C Project overlooked opportunities to reduce the lifecycle GHG emissions of the

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Alternative Portfolio by more than 500 kt CO₂e/year (i.e. from 611 kt CO₂e/year to 68 kt CO₂e/year).

Table 6. Annual GHG Emissions Estimates – Optimized Alternative Portfolio

<table>
<thead>
<tr>
<th>Alternative Portfolio</th>
<th>IRP GHG Combustion Emissions (kt CO₂e/year)</th>
<th>EIS GHG Lifecycle Emissions (kt CO₂e/year)</th>
<th>Optimized Lifecycle Emissions No MSW, 5% SCGT (kt CO₂e/year)</th>
<th>Optimized Lifecycle Emissions No MSW, 5% SCGT, DSM for 50% of SCGTs (kt CO₂e/year)</th>
<th>Optimized Lifecycle Emissions No MSW, 5% SCGT, DSM + storage for all SCGTs (kt CO₂e/year)</th>
</tr>
</thead>
<tbody>
<tr>
<td>GM Shrum</td>
<td>0</td>
<td>0</td>
<td>0</td>
<td>0</td>
<td>0</td>
</tr>
<tr>
<td>Revelstoke 6</td>
<td>0</td>
<td>0</td>
<td>0</td>
<td>0</td>
<td>0</td>
</tr>
<tr>
<td>MSW</td>
<td>217</td>
<td>217</td>
<td>0</td>
<td>0</td>
<td>0</td>
</tr>
<tr>
<td>Natural Gas (SCGTs)</td>
<td>294</td>
<td>336</td>
<td>102</td>
<td>51</td>
<td>0</td>
</tr>
<tr>
<td>Wind</td>
<td>0</td>
<td>58</td>
<td>68</td>
<td>68</td>
<td>68</td>
</tr>
<tr>
<td>Totals</td>
<td>511</td>
<td>611</td>
<td>171</td>
<td>119</td>
<td>68</td>
</tr>
</tbody>
</table>
5. Magnitude of the GHG emissions in context

5.1 Magnitude of GHG emissions

Optimizing the Alternative Portfolio, as described in section 4, substantially reduces its GHG emissions. The green bars in Figure 2, below, illustrate the annual average GHG emissions of the Site C Project, based on the estimates summarized in Table 1 above. The tall blue bar represents the GHG emissions of the Alternative Portfolio as developed by BC Hydro; the shorter bars illustrate the optimized approaches to this portfolio, as summarized in Table 6. These optimizations do not include the potential for further future reductions in GHG emissions from the Alternative Portfolio, or potential reductions from export of the Site C Project energy surplus, as discussed below.

As shown in Figure 2, the GHG emissions from the fully optimized Alternative Portfolio are equal to BC Hydro’s “conservative” estimate of emissions from the Site C Project, and less than its “maximum” estimate. The GHG emissions reduction benefit of the Site C Project compared to an optimized Alternative Portfolio is at most 0.1 Mt CO2e/year, equivalent to just 0.15% of British Columbia’s annual GHG emissions, or 3 days per year of operations of the proposed Pacific Northwest LNG export facility.

Figure 2


5.2 BC GHG emission reduction targets

In order to place in context any differences between portfolios in terms of GHG emissions, it is instructive to compare them against the current emissions and emission reduction targets for British Columbia, as shown below in Figure 3.

Once viewed at the appropriate scale, the differences between the portfolios are revealed to be extremely small. This disproves the common perception that the Site C Project provides a substantial benefit in terms of GHG emission reductions compared to the available alternatives.

As shown in Figure 2, above, the optimized Alternative Portfolio (0.068 Mt CO$_2$e/year to 0.171 Mt CO$_2$e/year), differs from the Site C Project “conservative” scenario (0.068 Mt CO$_2$e/year) by at most 0.1 Mt CO$_2$e/year. This difference represents about 0.15% of BC’s current emissions, 0.25% of BC’s 2030 target emissions and 0.75% of the BC’s 2050 target emissions.

5.3 Other BC GHG emissions

The maximum 0.1 Mt CO$_2$e/year difference between the Site C Project and the optimized Alternative Portfolio in terms of GHG emissions can also be considered in the context of other existing and potential future emission sources in British Columbia, as shown below in Figure 4.

The potential GHG emission reduction benefits of the Site C Project compared to the optimized Alternative Portfolio, if they exist at all, are about 7% of the annual emissions...
of the largest existing single emitter in the Province, the Spectra Energy Fort Nelson Gas Plant, as shown in Figure 4. The recently-approved Woodfibre LNG facility, even with its relatively low emissions intensity per tonne of LNG, is nearly 10 times the maximum annual GHG emission benefits of Site C compared to the optimized alternative portfolio. Were the Pacific Northwest LNG export facility to be approved, its annual emissions would be more than 120 times the potential GHG emissions benefits of Site C, and would also represent over 95% of British Columbia’s 2050 emissions reduction target set out in the Clean Energy Act.

Figure 4\textsuperscript{72,73,74,75}

\begin{figure}
\centering
\includegraphics[width=\textwidth]{GHG_Emissions_of_Alternative_Porfolios_Compared_to_Emission_Sources}
\caption{GHG Emissions of Alternative Porfolios Compared to Emission Sources}
\end{figure}

\begin{itemize}
\item \textsuperscript{72} Stantec. 2014. Pacific NW LNG Environmental Impact Statement and Environmental Assessment Certificate Application Section 7: Greenhouse Gas Management, p.7-14.
\item \textsuperscript{73} Environment and Climate Change Canada. 2016. Pacific Northwest Liquefied Natural Gas (LNG) Project Review of Related Upstream Greenhouse Gas (GHG) Emissions Estimates. Available at: \url{http://www.clea-
acee.gc.ca/050/documents/p80032/104795E.pdf}.
\item \textsuperscript{74} Environment Canada. 2014. Greenhouse Gas Emissions Reporting Program Online Data Search – Facility Reported Data.
\item \textsuperscript{75} Environment and Climate Change Canada. February 1, 2016. Woodfibre Liquefied Natural Gas (LNG) Project Review of Related Upstream Greenhouse Gas (GHG) Emission Estimates. Available at: \url{http://www.clea-
acee.gc.ca/050/documents/p80060/104688E.pdf}.
\end{itemize}
6. Additional considerations for comparing GHG emissions

6.1 Future opportunities for further GHG emission reductions

The GHG emissions analysis presented by BC Hydro in the IRP assumes that the electricity generation resources comprising the Alternative Portfolio will come into service all at once at the same time as the Site C Project. In fact, the resources in the Alternative Portfolio will be brought into service incrementally, only if and when required in response to increases in demand for energy and capacity. This reflects an advantage for the Alternative Portfolio that is not reflected in BC Hydro’s analysis.

BC Hydro’s presentations of cumulative and annualized GHG emissions both mask the fact that the GHG emissions for the Site C Project commence a full decade earlier than those of the Alternative Portfolio. As shown in Table 1, the GHG emissions of the Site C Project appear modest, but this is the result of the averaging of these emissions over a 108-year period. Site C entails the inevitable and immitigable release of 4 Mt CO$_2$e emissions or more before 2035, as a result of construction-related emissions and the fact that reservoir emissions are concentrated in the early years following inundation. Figure 5 illustrates this situation, where annual GHG emissions of the Site C Project rise sharply following inundation before declining over the next 20 years. The Alternative Portfolio follows a similar, though smaller, pattern as a result of the development of wind resources over a 10-year period beginning in 2028.

Figure 5.

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76 GHG Report, supra note 5, Table C.4 and Table C.6.
Figure 6 shows the cumulative GHG emissions of the Site C Project under the “likely” and “conservative” scenarios as well as the emissions of the optimized Alternative Portfolio presented in Table 6, with the resources developed over time based on the most likely resource sequence from the 2013 IRP. As the figure illustrates, depending on the extent of portfolio optimization, it will be several decades before the GHG emissions of the Alternative Portfolio exceed those of the Site C Project, if ever.

Figure 6.

This situation arises because the Site C Project entails a relatively large “pulse” of GHG emissions in the early years of operations, while the Alternative Portfolio commences with the development of capacity upgrades at Revelstoke and GM Shrum, which require no additional reservoir creation and result only in minimal GHG emissions associated with equipment manufacture and construction. Natural gas generation would not be required in the Alternative Portfolio until at least 2027, and wind generation until 2028, under the mid-load electricity demand scenario. These dates may be even later as a result of lower than expected demand growth, further delays or cancellations of LNG export facilities, increased self-generation, additional DSM, electricity storage, renewable fuel standards for natural gas, or other factors. An optimized Alternative Portfolio that excludes MSW generation, operates SCGTs only as necessary during

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77 IRP, supra note 2, Appendix 6A, p. 6A-27. This resource sequence was used for BC Hydro’s present value cost analysis and includes resources developed after the resources contained in the Clean + Thermal #2 portfolio used for GHG emission comparisons.

78 Ibid.
peak demand periods, and avails of contributions from DSM and storage (the lowermost blue line in Figure 5) will remain indefinitely below the cumulative GHG emissions of the Site C Project.

Even if the Alternative Portfolio is initially developed with SCGTs operating at a given capacity factor, over time this capacity factor can be reduced with additional capacity-focused DSM. The SCGTs can also be replaced at the end of their useful life with lower emission technologies, or the GHG emissions intensity of the natural gas can be lowered through a renewable fuel standard. An optimized Alternative Portfolio (the uppermost blue line in Figure 6) that initially avails of no capacity-focused DSM, no lower emission technologies and no renewable fuel standard has nearly 40 years to “bend the curve” below the GHG emissions of the Site C Project.

Beyond 2035, the GHG emissions in the Alternative Portfolio are depicted as changing linearly over time, due to ongoing fuel consumption. This is unlikely to be the case. One of the factors driving the use of SCGTs is their low capital cost, which means that they can be replaced in the future as better technologies arise, without significant capital loss. Furthermore, though these data do not take into account the replacement of wind turbines, with resulting manufacturing emissions, they also do not include the eventual turbine replacement for the Site C Project. Operations and maintenance activities would also contribute modest GHG emissions to both Site C and the Alternative Portfolio. These emissions are minimal or far in the future compared to the emissions from initial project development and inundation at Site C, and compared to initial development of wind resources and operation of SCGTs, if any, in the optimized Alternative Portfolio.

Ten years is a long time in the electricity business. Forty years is a technological eternity. Between 2005 and 2015, the average price of natural gas fell from US$8.69 to US$2.62 per million Btu, a remarkable decline of 70%, as a result of largely unanticipated technological developments.79 Utility scale solar PV systems declined by that same percentage in just over half that time.80 Over a forty-year period, the price of silicon crystalline photovoltaic cells has declined by over 99%.81 An optimized Alternative Portfolio has available to it all of the technological advances of the coming four decades or longer that would allow for additional reductions in potential GHG emissions in order to remain well below the emissions of the Site C Project.

This opportunity for improvement is unavailable to the Site C Project, since once it is constructed and operating, its GHG emissions are certain to occur.

81 BNEF. supra note 66.
6.2 GHG emission reductions resulting from potential Site C exports

Site C not assessed for export purposes

The need for the Site C Project was framed by BC Hydro in the context of domestic residential, commercial and industrial electricity requirements. In its IRP, BC Hydro concluded that there were no economically viable export opportunities:

BC Hydro concludes that, aside from monitoring, there are no actions BC Hydro should be taking because there are no suitable opportunities for the export of electricity from clean or renewable B.C. resources for the foreseeable future.

Consequently, BC Hydro does not perceive, at this time, any value in continuing to investigate and develop potential market opportunities for export sales. …[C]urrent market conditions do not warrant expenditures for export, and no expenditures are planned as part of the Recommended Actions.82

The Site C Project was not proposed as an export facility, either to meet the needs of export markets in the United States, or to meet potential future market opportunities that may be available as a result of Alberta’s decision to shutter its coal generation by 2030.83

Since the enactment of the CEA, the prospects of export sales of clean or renewable energy in excess of that required to meet B.C. self-sufficiency requirements have diminished considerably. Further, the prospects of such sales are not expected to materially improve over the short to medium term. The reasons include a significant recent increase in renewable energy resources in the WECC [Western Electricity Coordinating Council], the persistence of tax incentives available to U.S. producers, and the enactment of RPS standards in potential markets, particularly California, that exclude many clean or renewable B.C. resources.84

In other words, the purpose of the Site C Project, as proposed by BC Hydro, as evaluated in the IRP, and as assessed during the environmental assessment by the JRP was to meet British Columbia’s domestic electricity requirements and not those of some other jurisdiction. The Site C Project was not evaluated in the export context.

Potential GHG emission reductions in Alberta

Despite the lack of prior evaluation by BC Hydro, the Provincial government has acknowledged that it is now considering exporting energy and capacity from the Site C

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82 IRP, supra note 2, Chapter 5 Planning Environment, pp. 5-53 to 5-54.
84 IRP, supra note 2, Chapter 5 Planning Environment, p.5-51.
This raises the potential that electricity generated at Site C could reduce GHG emissions from the electricity sector in the neighbouring Province. Whether this occurs would depend on the extent to which electricity from the Site C Project displaces competing electricity generation with a higher or lower GHG emissions intensity.

Alberta has recently indicated that: “By 2030, two-thirds of Alberta’s coal generating capacity will be replaced by renewable energy; one-third will be replaced by natural gas.” This is an important consideration in evaluating the potential GHG emissions reductions from the Site C Project, namely that coal generation will be replaced in Alberta regardless of whether or not energy or capacity from the Site C project is exported there. **Site C would not necessarily displace coal generation in Alberta.** Site C competes with the other forms of generation that will be developed since coal generation can no longer be refurbished or replaced with new coal generation.

The extent of potential GHG emission reductions resulting from the Site C Project will depend on several factors, including the duration of any export contracts, whether additional transmission can or will be developed to support exports, and how BC Hydro replaces exports beyond the Site C energy surplus. Long-term exports of firm energy and dependable capacity from Site C to Alberta would trigger a requirement for additional dependable capacity resources in BC (and any associated GHG emissions), given BC Hydro’s IRP identified a need for capacity by F2019, and the more recent 2016 load resource balance updated that requirement to F2020.

Electricity exported to Alberta during the period when Site C that is surplus to BC Hydro’s needs would displace or delay other generation that would otherwise be dispatched or developed. The precise mix of natural gas, wind, hydro, solar, geothermal and biomass that will be developed cannot be known with certainty, but the range of the potential GHG emission reductions during the Site C energy surplus period can be estimated.

Table 7 presents the estimated surplus energy projected for the BC Hydro integrated system in the utility’s most recent load resource balance for the years following the commissioning of the Site C Project. It also presents a preliminary estimate of the GHG emission reductions from exporting this surplus to Alberta, based on the assumption that one-third of the replacement energy would otherwise come from natural gas and two-thirds from renewables, as per the Government of Alberta policy objective.

This GHG emission offset of 2.4 Mt CO₂e would lower the cumulative GHG emissions from the Site C Project to a level more similar to that of an optimized Alternative

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Portfolio containing at least some capacity-focused DSM (see Figure 6). Whether the Site C Project actually displaces this quantity of GHG emissions depends on the emissions intensity of competing generation resources that would otherwise be developed in Alberta in the period 2024-2030.

**Table 7. Site C energy surplus GHG emissions reductions in Alberta**

<table>
<thead>
<tr>
<th>Year</th>
<th>Site C Energy Surplus</th>
<th>Natural Gas</th>
<th></th>
<th></th>
<th>Renewables</th>
<th></th>
<th></th>
<th>Total Emissions Reduction</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>(GWh/year)</td>
<td>GWh/year</td>
<td>(t CO₂e/GWh)</td>
<td>GWh/year</td>
<td>(t CO₂e/GWh)</td>
<td>(t CO₂e)</td>
<td></td>
<td></td>
</tr>
<tr>
<td>2025</td>
<td>3,277</td>
<td>1,092</td>
<td>545</td>
<td>2,185</td>
<td>15</td>
<td>628,092</td>
<td></td>
<td></td>
</tr>
<tr>
<td>2026</td>
<td>3,241</td>
<td>1,080</td>
<td>545</td>
<td>2,161</td>
<td>15</td>
<td>621,192</td>
<td></td>
<td></td>
</tr>
<tr>
<td>2027</td>
<td>2,711</td>
<td>904</td>
<td>545</td>
<td>1,807</td>
<td>15</td>
<td>519,608</td>
<td></td>
<td></td>
</tr>
<tr>
<td>2028</td>
<td>1,866</td>
<td>622</td>
<td>545</td>
<td>1,244</td>
<td>15</td>
<td>357,650</td>
<td></td>
<td></td>
</tr>
<tr>
<td>2029</td>
<td>1,082</td>
<td>361</td>
<td>545</td>
<td>721</td>
<td>15</td>
<td>207,383</td>
<td></td>
<td></td>
</tr>
<tr>
<td>2030</td>
<td>331</td>
<td>110</td>
<td>545</td>
<td>221</td>
<td>15</td>
<td>63,442</td>
<td></td>
<td></td>
</tr>
</tbody>
</table>

Evidence from Ontario, which shuttered all of its coal-fired generation over a ten-year period (2005-2014), suggests a potential pattern for development of the alternative resources to coal generation in Alberta. Figure 7 presents the 17,304 MW of transmission-connected and embedded generating capacity contracted by the Ontario Independent Electricity System Operator (IESO) over the period 2004-2016. Combined-cycle, simple-cycle and combined heat and power natural gas facilities account for 36%, which is not dissimilar to the 33% policy objective of the Government of Alberta. This suggests that 2.4 Mt CO₂e is a reasonable estimate of the cumulative emissions that could be displaced by the surplus energy from the Site C Project.

However, the timing of any exports to Alberta is an additional and important consideration, particularly in light of the costs of the low-carbon alternatives that are available in Alberta. To date, there has been no public indication that the Alberta Government or any commercial entity in Alberta would consider paying the actual cost of electricity from the Site C Project, which would also need to include any additional transmission-related costs. In the 2013 IRP, BC Hydro estimated the cost of delivering electricity to the BC lower mainland from Site C at $94/MWh (before capacity benefits), and the cost of delivery to load centers in Alberta would likely be similar, ignoring additional transmission costs. Transmission development in BC or Alberta, and any transmission tariffs in Alberta would add to this cost. As a result, the cost of energy

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90 IRP, supra note 2, Chapter 6 Resource Planning Analysis, p.6-28.
from Site C is substantially higher than the regulated rates in Alberta and the wholesale market pool price, both of which are on the order of $35/MWh\textsuperscript{91,92} and, importantly, higher than the cost of electricity generated from other alternatives available in Alberta, including natural gas,\textsuperscript{93} wind and, potentially by 2024, utility-scale solar PV.

Figure 7

Alberta has superior wind resources to British Columbia and Ontario, where a recent competitive process by the Independent Electricity System Operator (IESO) saw 300 MW contracted at a weighted average price of $86/MWh with a range of about $65 to $105/MWh.\textsuperscript{94} The Government of Alberta recently tasked the Alberta Electric System Operator (AESO) with developing a program to bring on new renewable generation capacity to 2030. The program is still under development with contracts to be awarded in 2017, and with first projects in service by 2019.\textsuperscript{95} Average prices are therefore not yet known, but would be expected to be lower than in Ontario and on the order of $50 to $80/MWh with the average in the $60 to $70/MWh range.

\textsuperscript{92} AESO. 2016. AESO 2015 Annual Market Statistics, p.3.
\textsuperscript{93} Electricity generated from combined cycle natural gas would be available in Alberta at approximately $60/MWh as it is in BC. See IRP, supra note 2, Chapter 3 Resource Options, Table 3-17.
\textsuperscript{94} Ontario Independent Electricity System Operator. 2016. Large Renewable Procurement. Available at: http://www.ieso.ca/Pages/Participate/Generation-Procurement/Large-Renewable-Procurement/default.aspx
\textsuperscript{95} Alberta Electricity System Operator. 2016. Renewable Electricity Programs. Available at: http://www.aeso.ca/rep/.
The cost of on-shore wind energy is expected to continue to decline, with the International Renewable Energy Agency (IRENA) recently projecting costs declines of 26% to 2025, and Bloomberg New Energy Finance (BNEF) projecting costs declines of 41% to 2040. The extent to which these declines are realized in Alberta depends on a number of factors including improvements in wind turbine efficiency and design, government policy, and technology adoption. A decline of 26% in the cost of wind energy in Alberta would mean a weighted average price on the order of $45 to $55/MWh in 2025 when energy from Site C would become available. This would be about half the full cost of surplus energy from Site C, presuming no transmission costs or tariffs.

Regarding solar energy, utility-scale solar PV is not currently competitive in Alberta. However, as with wind energy, the Province has superior solar resources to British Columbia and to Ontario, where IESO’s competitive process saw 140 MW of utility-scale solar PV contracted at a weighted average price of $157/MWh with a range over $140/MWh to $180/MWh. Considering Alberta’s solar insolation advantage over Ontario, and presuming the implementation of appropriate policies and market development, average prices in 2016 would be expected to be on the order of $125 to $150/MWh, in the event that any proponents were to respond to the AESO’s upcoming competitive procurement.

Declines in the cost of utility-scale solar PV are also expected to continue in the coming decades. BNEF projects an average cost decline in utility scale solar PV on the order of 60% out to 2040. In its recent analysis, IRENA projected a 59% decline in utility-scale solar PV costs by 2025. Whether these declines are realized in Alberta depends on a number of factors including: continued declines in installed costs, operations and maintenance cost declines, improvements in capacity factors, government policy, and technology adoption. A decline of 40% by 2025, in line with the BNEF projections, would mean a weighted average price on the order of $75 to $90/MWh, while a decline of 60% would see weighted average prices on the order of $50 to $60/MWh just when energy from Site C would become available.

Considering the continued declines in the price of energy from on-shore wind and utility-scale solar PV to well below the cost of delivering energy to Alberta from Site C, it is far from obvious that the Alberta Government or any commercial entity in Alberta would be willing to contract for the delivery of that energy, or to pay for the transmission investments required for that delivery. While Site C potentially has the additional advantage of providing dependable capacity, that advantage must consider the additional costs and environmental effects associated with transmission development, the relatively low costs (but higher GHG emissions) of providing that dependable

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capacity in Alberta using combined-cycle natural gas turbines, and the potential that considerable dependable capacity can be provided in Alberta at low costs and low emissions using a combination of SCGTs, capacity-focused DSM (including demand response and direct load control), and other dependable sources of capacity including geothermal and energy storage similar to the optimized Alternative Portfolio developed in this report. There has been no review to date by the BC Utilities Commission or an Alberta regulator of the costs of exporting energy or capacity from the Site C Project to Alberta.
How do B.C.’s climate action commitments stack up?

Rising emissions in B.C. contrast with progress in Alberta, Ontario and Quebec

by Josha MacNab and Maximilian Kniewasser  |  June 14, 2016

Summary

A look at Canada’s four most populous provinces shows that B.C. is lagging behind on commitments to new climate action. Alberta, Ontario and Quebec are all projected to see decreases in carbon pollution by 2030 based on the actions they’ve taken or committed to. Conversely, B.C. is projected to see a 39 per cent increase in emissions by 2030. Meanwhile, the province is sure to miss its legislated emissions reduction target for 2020. However, the Climate Leadership Team’s recommendations would see B.C. get back on track to meeting its 2050 emissions target.

The government of British Columbia is poised to announce the first update to its climate plan since 2008. Due to a lack of climate action, carbon pollution in B.C. is rising too quickly for the province to meet its legislated emissions target for 2020. To get B.C. back on track, the new Climate Leadership Plan will need to set a clear path to achieving the province’s 2050 target and position the economy to thrive in a low-carbon world.

B.C. has a history of successful climate action. Under the first Climate Action Plan in 2008, a package of policies and programs were implemented that worked together to see B.C.’s emissions go down. These effective policies included:

1. **Carbon tax**: Introduced at $10 per tonne and increased annually by $5 per tonne until 2012, the carbon tax contributed to a strong B.C. economy and helped to create the conditions for the emissions reductions B.C. saw over this period.¹

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2. **Clean energy requirements:** The Clean Energy Act kept the electricity supply low in carbon, and the ban on coal-fired electricity generation avoided 1.7 megatonnes (Mt) of emissions from two proposed coal plants.²

3. **Low carbon fuel standard:** Targeting a 10 per cent reduction in intensity of carbon pollution from motor fuel by 2020, the low carbon fuel standard resulted in the avoidance of 0.9 Mt of emissions in 2012.³

However, since the introduction of the 2008 plan, climate action has stalled in B.C. In addition to being slow to implement new policies and programs designed to reduce B.C.’s emissions, the government has kept the carbon tax — its most effective tool for the job — frozen since 2012.

As a result of inaction, B.C.’s carbon pollution is increasing. Between 2011 and 2014, it climbed by 1.8 Mt of carbon dioxide equivalent (CO₂e) — akin to adding 380,000 cars to our roads.⁴ This trend is projected to continue in the absence of new climate action. Government forecasts suggest B.C.’s emissions will grow to 83 Mt, or 32 per cent above the 2014 level, by 2030.⁵

This increase in emissions is largely due to a projected increase in oil and gas development, including liquefied natural gas (LNG). Over 80 per cent of the emissions increase between 2014 and 2030 is projected to come from this sector. The remaining projected increase comes primarily from emissions-intensive and trade-exposed industries and the building sector.⁶ A strong Climate Leadership Plan would decrease all of these projections.

A recent report by the Canadian Deep Decarbonization Pathways Project Team modelled the projected changes in emissions from all Canadian provinces and territories based on their committed actions to date. A look at Canada’s four most populous provinces shows that B.C. is lagging behind on commitments to new climate action. Figure 1 shows the change in emissions projected in each province by 2030 as a percentage of their total emissions in 2014. Alberta, Ontario and Quebec are all projected to see decreases in emissions of 26, 22 and 23 per cent,

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⁶ Adapted from Canada’s Second Biennial Report on Climate Change.
respectively, by 2050 based on the actions they’ve taken or committed to. Conversely, B.C. is projected to see a 39 per cent\(^7\) increase in emissions by 2030.\(^8\)

**Figure 1: Change in emissions by 2030 for Canada’s most populous provinces**

![Change in emissions by 2030 for Canada’s most populous provinces](image)

Fortunately, B.C. has a near term opportunity to change its emissions trajectory. The **B.C. Climate Leadership Team recommendations** represent a collection of actions and policy changes that would see B.C. get back on track to meeting its 2050 emissions reduction target. The 32 recommendations include:

- **Buildings**: Reduce emissions from buildings by 50 per cent by 2030.
- **Transportation**: Set a 2030 target for the low carbon fuel standard and establish a new zero emission vehicle standard.

\(^7\) The Canadian Deep Decarbonization Pathways Project Team’s modelling shows a slightly higher projection for B.C.’s emissions in 2030 than the federal government’s modelling due to different assumptions. Notably, the DDPP team modeled lower oil prices, which drive carbon pollution from end-use higher due to insufficient price signals on emissions. This is further exacerbated by the decrease of B.C.’s carbon tax in real terms over the study period.

\(^8\) Actions modelled in this analysis include Ontario cap and trade, Alberta Climate Leadership Plan, B.C.’s current carbon tax and Quebec cap and trade. For more details on the specific policies included, see Dave Sawyer and Chris Bataille, *Still Minding the Gap: An Assessment of Canada’s Greenhouse Gas Reduction Obligations* (Canadian Deep Decarbonization Pathways Project Team, 2016). [http://climateactionnetwork.ca/2016/04/26/still-minding-the-gap/]
• **Methane**: Cut methane emissions from the natural gas sector by 40 per cent over the next five years.

• **Carbon tax**: Unfreeze the carbon tax and begin increases of $10 per tonne per year while protecting affordability for British Columbians and mitigating competitiveness impacts.

• **Target**: Set a new emissions target of 40 per cent below 2007 levels by 2030.

However, anything less than the full package of recommendations, including an increasing carbon tax, will mean B.C. will miss its 2050 target.

B.C. gained its reputation as a climate leader with the introduction of the 2008 Climate Action Plan and carbon tax. But B.C.’s inaction on climate and freeze of the carbon tax since 2012 has lost the province its leadership position.

While Alberta’s, Ontario’s and Quebec’s plans are all projected to bring down emissions, B.C.’s are projected to increase. Adopting the Climate Leadership Team recommendations would help put B.C. back on track.
MAIN CIVIL WORKS CONTRACT
SCHEDULE 2
GENERAL CONDITIONS

1 INTERPRETATION

1.1 Definitions

In this Schedule 2 [General Conditions], in addition to the definitions set out in Schedule 1 [Definitions and Interpretation]:

“Actual Good Weather Days” means the sum of the Good Weather Days and Partial Good Weather Days which actually occurred during the applicable Baseline Work Period;

“Administrative Correspondence” has the meaning set out in Section 2.1(a)(ii) of this Schedule 2 [General Conditions];

“Apprentices Policy” has the meaning set out in Section 6.24 of this Schedule 2 [General Conditions];

“Baseline Work Period” has the meaning set out in Section 13.3(a) of this Schedule 2 [General Conditions];

“BC Hydro Delay” has the meaning set out in Section 12.1 of this Schedule 2 [General Conditions];

“Climate Station” means climate station 7;

“Confidential Information” has the meaning set out in Section 20.1 of this Schedule 2 [General Conditions];

“Consequential Damages” has the meaning set out in Section 24.2 of this Schedule 2 [General Conditions];

“Contract Records” has the meaning set out in Section 2.1(a) of this Schedule 2 [General Conditions];

“Contractor Delay” has the meaning set out in Section 12.2 of this Schedule 2 [General Conditions];

“Contractor’s Daily 72 Hour Confirmation” has the meaning set out in Section 7.6(b) of this Schedule 2 [General Conditions];

“Default Costs” has the meaning set out in Section 15.3(c) of this Schedule 2 [General Conditions];

“Design-Build Work” has the meaning set out in Section 8.1 of this Schedule 2 [General Conditions];

“Document” has the meaning set out in Section 2.1(b) of this Schedule 2 [General Conditions];

“Document Number” has the meaning set out in Section 2.1(c) of this Schedule 2 [General Conditions];

“Extreme Weather Delay” has the meaning in Section 13.4(b) of this Schedule 2 [General Conditions];

“General Site Documents” has the meaning set out in Section 5.5 of this Schedule 2 [General Conditions];
16.2 Termination for Cause

If the Contractor terminates the Contract under Section 16.1 of this Schedule 2 [General Conditions], then BC Hydro will, in full satisfaction of all claims the Contractor may have, pay the Contractor:

(a) all compensation owed in accordance with the Contract for all Work performed, including all materials and equipment supplied for incorporation into the Work, in accordance with the Contract Documents up to the date of the termination;

(b) all reasonable and substantiated third party cancellation charges, if any, incurred by the Contractor to the date of termination, provided such charges could not have been reasonably avoided or mitigated by the Contractor; and

(c) the Contractor’s reasonable and substantiated Direct Costs for demobilization from the Contractor’s Work Areas, plus a mark-up of 15% on such Direct Costs.

For certainty, the Contractor will not be entitled to, nor will the Contractor make a claim for, Consequential Damages.

17 Suspension or Termination of Contract Other Than for Default

17.1 Suspension or Termination for Convenience

BC Hydro may, by written notice to the Contractor’s Representative, at any time at BC Hydro’s convenience and in its sole discretion, suspend or terminate the Contract, in whole or in part, stating the extent and effective date of such suspension or termination, and, upon receipt of such written notice, the Contractor will:

(a) wind down all suspended or terminated Work in accordance with such notice and in a manner such that BC Hydro receives the benefit of all completed Work;

(b) with respect to the terminated portions of the Work, if any, on the written direction of Hydro’s Representative:

(i) assign to BC Hydro, in the manner and to the extent directed by BC Hydro, all of the Contractor’s rights under purchase orders and agreements with any first tier Subcontractors as identified by BC Hydro; and

(ii) terminate purchase orders and agreements with first tier Subcontractors, to the extent that they are not assigned to BC Hydro;

(c) take any necessary action, including re-possession, to protect property in the Contractor’s possession in which BC Hydro has or may acquire an interest, including any BC Hydro Property;

(d) continue and complete performance of the continuing portion of the Work, if any, in accordance with the Contract Documents;

(e) provide suggestions to BC Hydro as to the best methods of mitigating any Claims, costs or delays arising from the suspension or termination of all of portions of the Work;

(f) provide all records and documents, as required by the Contract, to BC Hydro relating to the terminated portion of the Work, if any; and
17.2 Rights upon Termination for Convenience

In the event of termination under Section 17.1 of this Schedule 2 [General Conditions], BC Hydro will, in full satisfaction of all claims the Contractor may have, pay the Contractor:

(a) all compensation owed in accordance with the Contract for all Work performed, including all materials and equipment supplied for incorporation into the Work, in accordance with the Contract Documents up to the date of the termination;

(b) all reasonable and substantiated third party cancellation charges, if any, incurred by the Contractor to the date of termination, provided such charges could not have been reasonably avoided or mitigated by the Contractor; and

(c) the Contractor’s reasonable and substantiated Direct Costs for demobilization from the Contractor’s Work Areas, plus a mark-up of 15% on such Direct Costs.

For certainty, the Contractor will not be entitled to, nor will the Contractor make any claim for, Consequential Damages.

17.3 Obligations During Suspension

During any period of suspension, the Contractor will not remove any Work or any equipment and materials, including BC Hydro Property, from the Contractor’s Work Areas without the prior written consent of Hydro’s Representative, and will take all commercially reasonable steps to secure and make safe all Work and all such equipment and materials at the Site, including BC Hydro Property, if any. At any time after the commencement of such period of suspension, BC Hydro may give written direction to the Contractor to resume performance of the suspended Work, and, upon receipt of such direction, the Contractor will so resume within the time specified in such direction by Hydro’s Representative, acting reasonably.

In the event of suspension under Section 17.1 of this Schedule 2 [General Conditions], and provided that such suspension is not due to a default of the Contractor, BC Hydro will, in full satisfaction of all claims the Contractor may have, reimburse the Contractor for the Contractor’s Direct Costs, including stand-by equipment rental rates for any equipment that the Contractor may rent or own, personnel demobilization and remobilization costs and additional Site overhead costs, incurred in complying with the requirements of this Section 17.3, provided such costs could not have been reasonably avoided or mitigated by the Contractor, plus a mark-up of 15% on such costs.

At the end of each month during a suspension, the Contractor may submit an invoice to BC Hydro, along with all supporting documentation reasonably required by BC Hydro, which fully details the Direct Costs claimed by the Contractor in accordance with this Section 17.3 for that month. BC Hydro will pay to the Contractor the amount it approves within 60 days of receipt of such an invoice.

For greater certainty, the Contractor will not be entitled to, nor will the Contractor make any claim for, Consequential Damages.

The Work Program and Schedule will be extended to cover the complete period of the suspension.

17.4 Termination for Force Majeure

Either party may, on 14 days written notice to the other party, terminate the Contract if an event of Force Majeure has delayed the Contract for a period greater than 365 days for a single event, or 730 days in the
PART ONE SUMMARY AND RECOMMENDATIONS

CHAPTER I - REPORT SUMMARY

1.0 INTRODUCTION

In September 1980, Hydro applied to the government of British Columbia for an Energy Project Certificate to allow it to build a hydroelectric generating station and related transmission facilities. The hydro station, known as Site C, would be located approximately 7 km southeast of Fort St. John on the Peace River (see Figures 1 and 2).

The government referred Hydro's application to the B.C. Utilities Commission under Part 2 of the new B.C. Utilities Commission Act for review and recommendations. The terms of reference for this review call for an examination of the project's justification, design, impacts and other relevant matters. They specifically direct the Commission to recommend whether an Energy Project Certificate should be issued, and if so, what conditions should be attached.

The Commission held formal, local community and special native hearings to hear and examine evidence on all aspects of the project. Over 70 panels of witnesses made presentations during the formal hearings and over 100 individuals made presentations during the local community and special native hearings. The Commission's conclusions, based on the evidence and submissions, are summarized in this chapter.
The Commission notes, however, that Hydro's financing abilities are predicated on the province's 100% guarantee of its borrowing. The Commission also notes that the regulatory environment in which Hydro operates could affect the availability and cost of capital. A prolonged shortfall in meeting its financial targets due to falling markets, operating inefficiencies or legislative and regulatory constraints would adversely affect Hydro's ability to raise capital.

The Commission concludes that, while the rate impacts of Site C could be moderate, they could become significantly larger if the project is built prematurely, if costs escalate or if real interest rates increase above the levels assumed by Hydro. The Commission is confident Hydro can manage its construction costs effectively. With regard to interest rates, the Commission notes that falling inflation rates may have the effect of increasing the real cost of money borrowed at locked-in rates. Opportunities for flexible financing (e.g. better redemption provisions) are important in this regard. With regard to timing, the Commission concludes that underutilization would increase the rate impact. This possibility, particularly in the context of relatively poor export markets, is an important reason for the government and Hydro to guard against starting construction prematurely.

2.4 Commission's Position on Project Justification

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 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 (l) an acceptable forecast demonstrates that construction must begin immediately in order to avoid supply deficiencies and (2) a comparison of alternative feasible system plans demonstrates, from a
social benefit-cost point of view, that Site C is the best project to meet the anticipated supply deficiency. These matters should be reviewed by Cabinet in the fall of 1984 as recommended in Chapter X.

3.0 PROJECT DESIGN AND SAFETY

Hydro presented a detailed preliminary design at the hearings. It indicated that this would evolve into a final design as the project progressed and would be subject to extensive internal and external checks to ensure its reliability.

Hydro testified that the designs of the dam, spillway and powerhouse were carried out according to sound engineering principles by a thoroughly experienced staff and reviewed by renowned experts. In the highly unlikely event that the dam failed, the failure would be gradual. The dam would not be over-topped by slide-induced waves in the reservoir. Hydro concluded that, under all foreseeable circumstances, downstream warning could be provided in time to avoid loss of life.

The Commission concludes that the design presented by Hydro for Site C is sound and reflects concern for public safety. The Commission further concludes that Hydro's system of internal and external checks ensures a safe design.

Hydro testified that reservoir bank stability was a matter of on-going concern and that it had conducted extensive studies to predict areas most susceptible to instability. In addition, it proposed a comprehensive monitoring program to be conducted after the reservoir is filled to identify dangerous or unstable areas. The only area in which Hydro predicted a problem with bank stability that might endanger existing structures was immediately east of the bedrock strata at Hudson's Hope for a distance of 1,300 meters. Hydro proposed to construct a protective berm in that area.

The Commission concludes that, as long as Hydro diligently conducts the monitoring program it has proposed, the problems of bank instability arising