Une expertise en énergie
au service de l'avenir

April 2014

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

Philip Raphals
Executive Director

Helios Centre

326, boul. Saint-Joseph Est, bureau 100
Montréal (Québec) Canada H2T 1J2
Téléphone : (514) 849 7900
Télécopieur : (514) 849 6357
sec@centrehelios.org
www.centrehelios.org

Table of Contents

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

[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..."[2]

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.[3]

2.2. Purpose of the Project

In the EIS, BC Hydro states:

> The purpose of the Project is to:

---

[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).

- 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. …[4]

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

[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 PROPONENT'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% * 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.[5] 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.[6]

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.

---

[5] Rebuttal Testimony with respect to the Submissions of Philip Raphals, p. 14.

[6] P. Raphals, Response to BC Hydro's Rebuttal Testimony, pp. 14-18.

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.[8] (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.[9] 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".

---

[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.

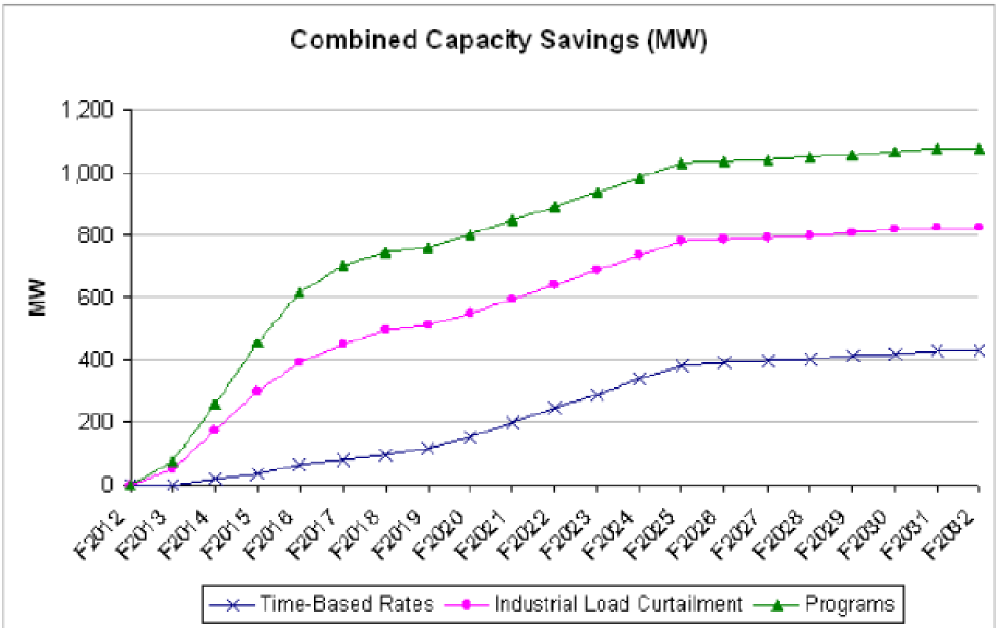
Not only does BC Hydro inappropriately exclude all DSM capacity initiatives, it has also chosen to completely ignore the capacity-saving potential of time-of-use rates, which it had recognized in its 2012 Draft IRP.

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.

Figure 1. Figure 3-4 of the 2012 Draft IRP



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.[10]

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

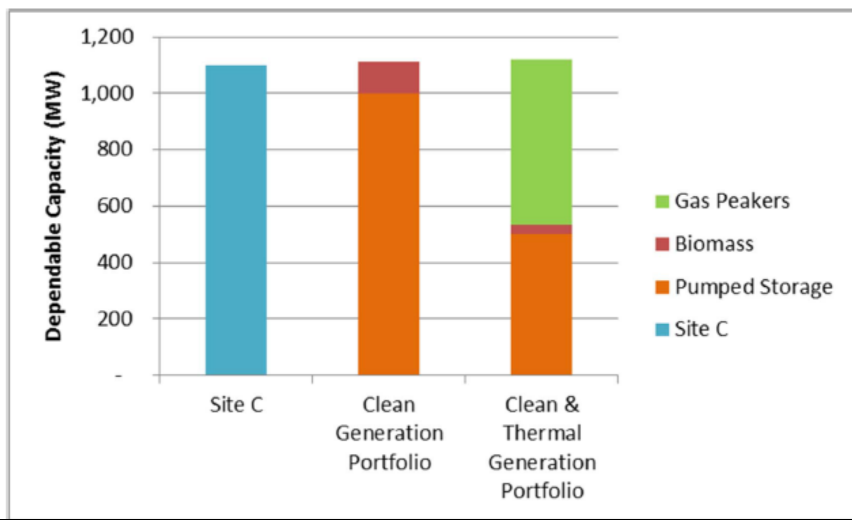
The Block Analysis compares Site C to similarly sized blocks of energy and capacity from other sources. This approach is fundamentally flawed. The commissioning of Site C would be accompanied by enormous capacity and energy surpluses, especially in low-load scenarios, and, as we shall see below, the 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.

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.[11] 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

---

[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.[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, **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.[13]

[12] The new LNG loads do not include the energy required for compression, which it is assumed will be provided by natural gas.

[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.

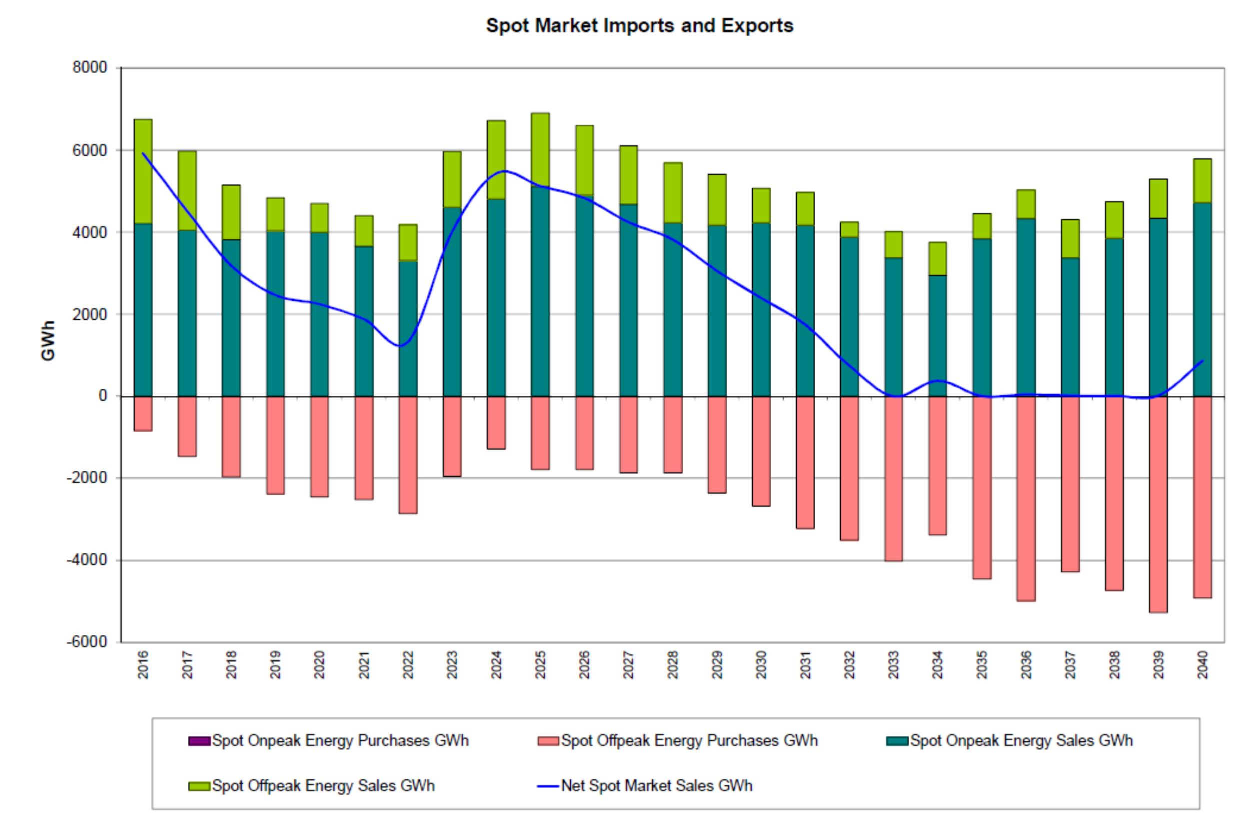
There is no way to develop the Site C project without creating these large surpluses. However, that is not true for the resources that make up the other two Block Portfolios (Clean and Clean+Thermal). **A present value cost comparison between these three Block Portfolios is thus entirely misleading.**

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."[14] 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.

[14] BC Hydro, Draft IRP, August 2013, Appendix 6A, Scenario M&M_1LC_NN0_05Q, p. 6A-40.

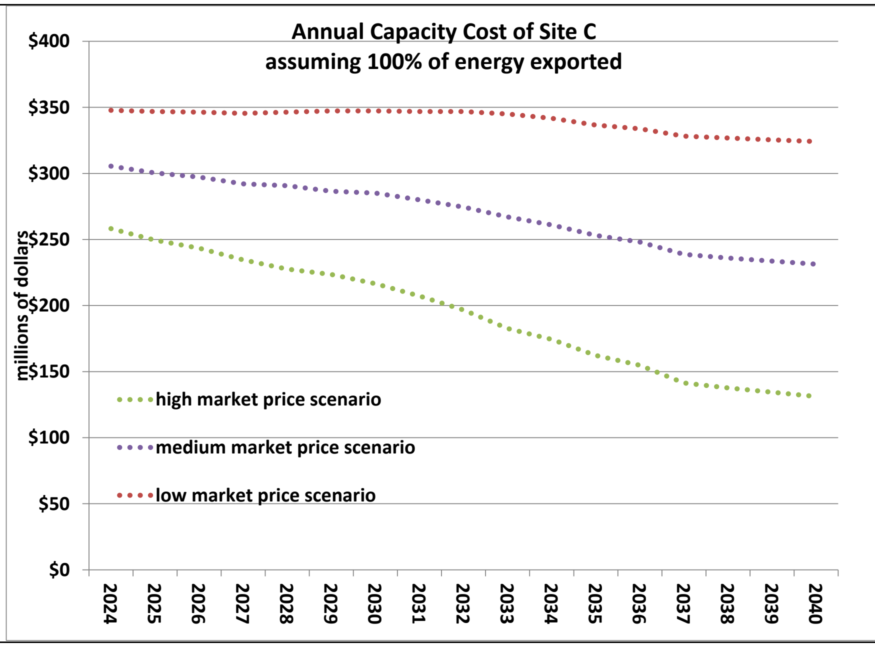
Figure 3. Site C Base Case



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.[15]

Figure 4.



This is much higher than the cost of the other capacity resources considered in the IRP:

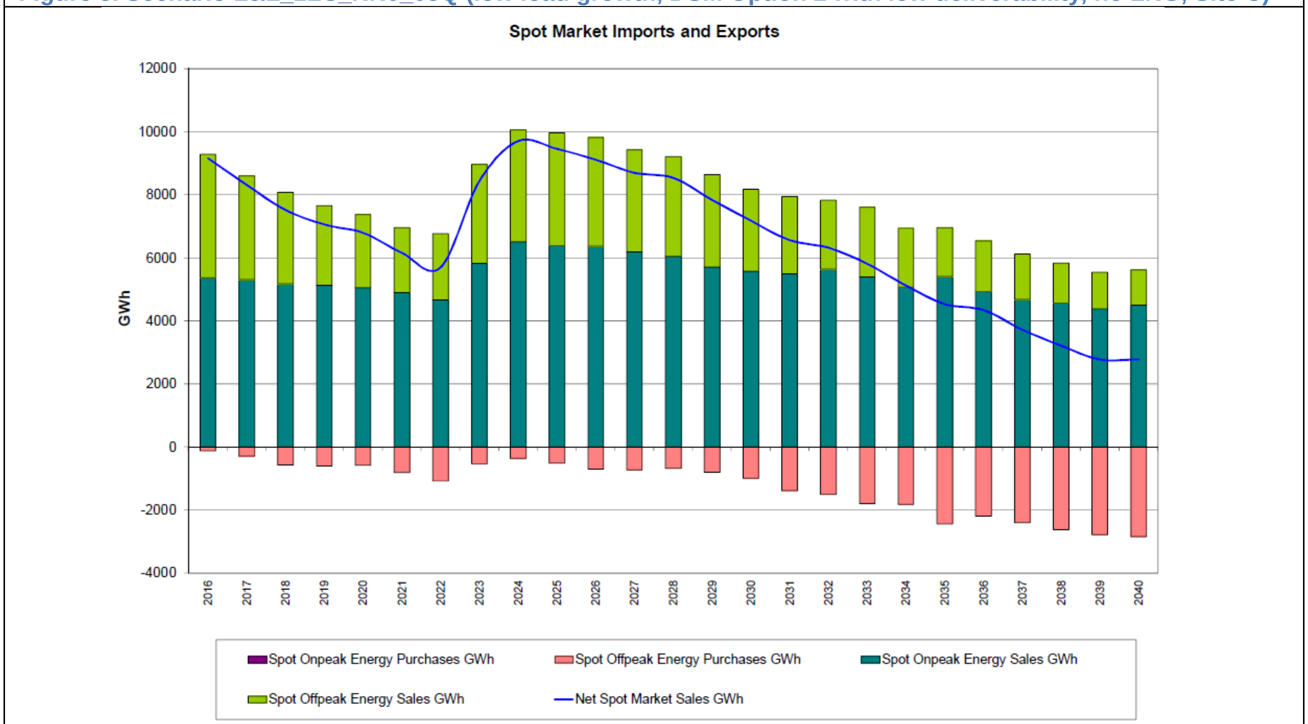
	Capacity Cost ($/kW-yr)	Source
SCGT	$100	Evidentiary Update, p. 60
Revelstoke Unit 6	$50	Evidentiary Update, p. 60
GSM Units 1-5	$35	Evidentiary Update, p. 60
Industrial load curtailment	$45	2013 IRP, Table 3-6, p. 3-30
Capacity-Focused Programs	$69	2013 IRP, Table 3-6, p. 3-30
TOU Rates	Very low	2012 IRP, Figure 3-5, p. 3-21

[15] BC Hydro acknowledges this in its Rebuttal Testimony, p. 12, Figure 1.

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.[16]

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[17]), 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.

---

16 BC Hydro, 2013 Final IRP, Appendix 6A, Table 4, p. 6A-37 (small gap portfolios).

17 For the years 2024 through 2040. BC Hydro, 2013 Final IRP, Appendix 5A, p. 5A-7.

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:

Figure 6. BRP without LNG (Site C, IRP) – Energy

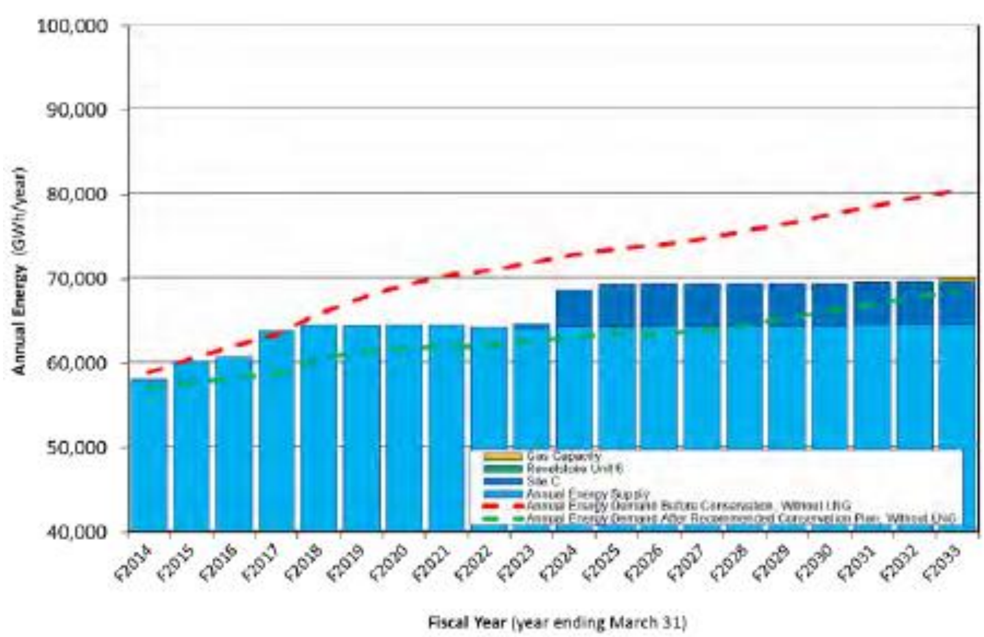
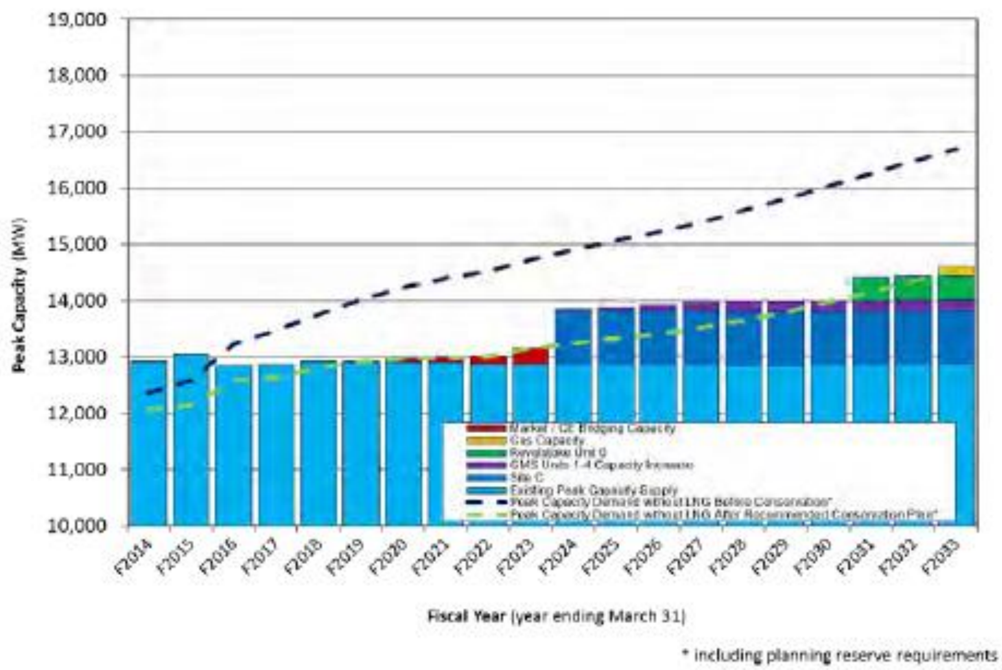


Figure 7. BRP without LNG (Site C, IRP) – Capacity

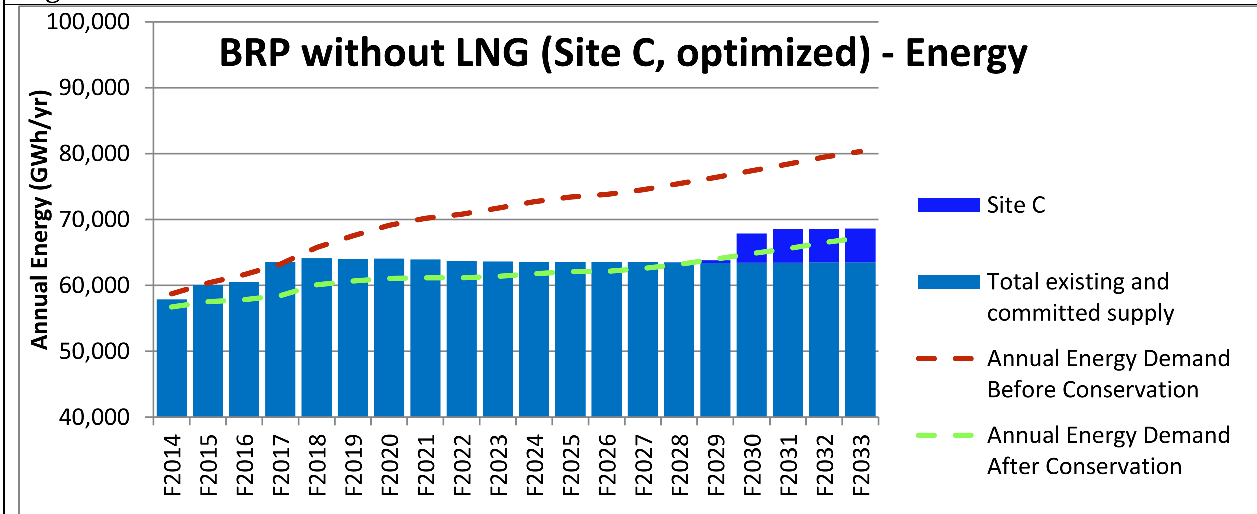


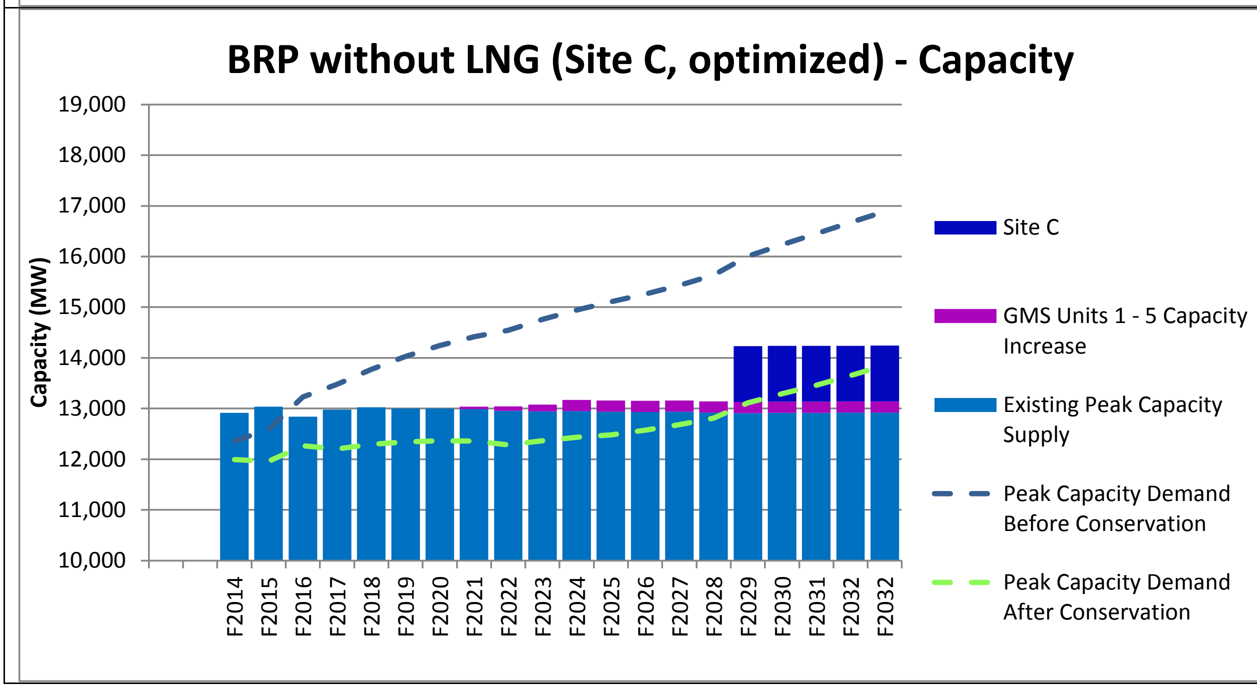
In this scenario, all of the energy and most of the capacity of Site C are surplus to BC Hydro's needs (the dashed green line, which represents demand after conservation) upon commissioning.

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.

Figure 8





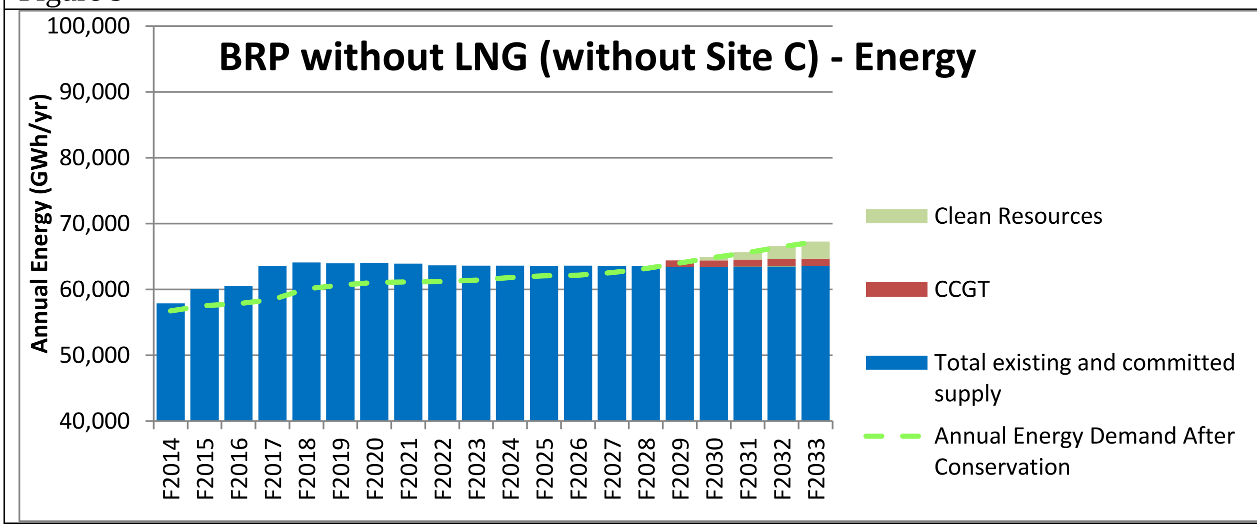
4.1.3. BRP without LNG, without Site C

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.[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.

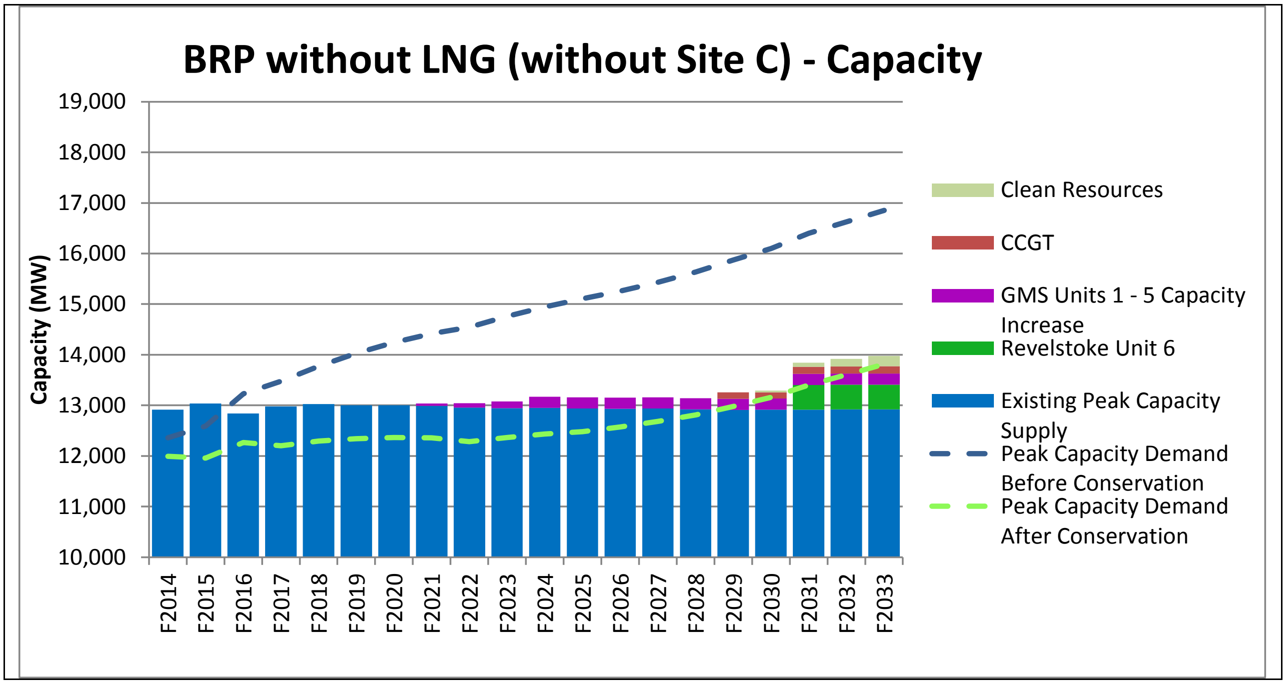
Capacity and energy balances for this portfolio are presented in Appendix 1.

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.

Figure 9



[21] In practice, this would probably mean building a 150 MW CCGT in F2029 and operating it at the average levels indicated here.

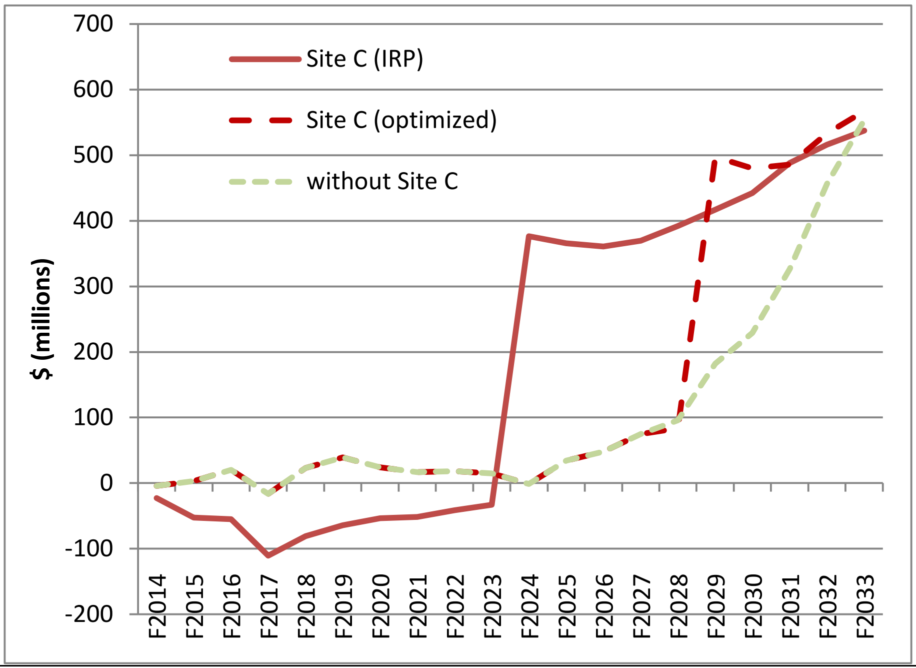


4.1.4. Differential cost comparison

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.

Figure 10. BRP (no LNG): Annual differential costs (capacity, energy and DSM)

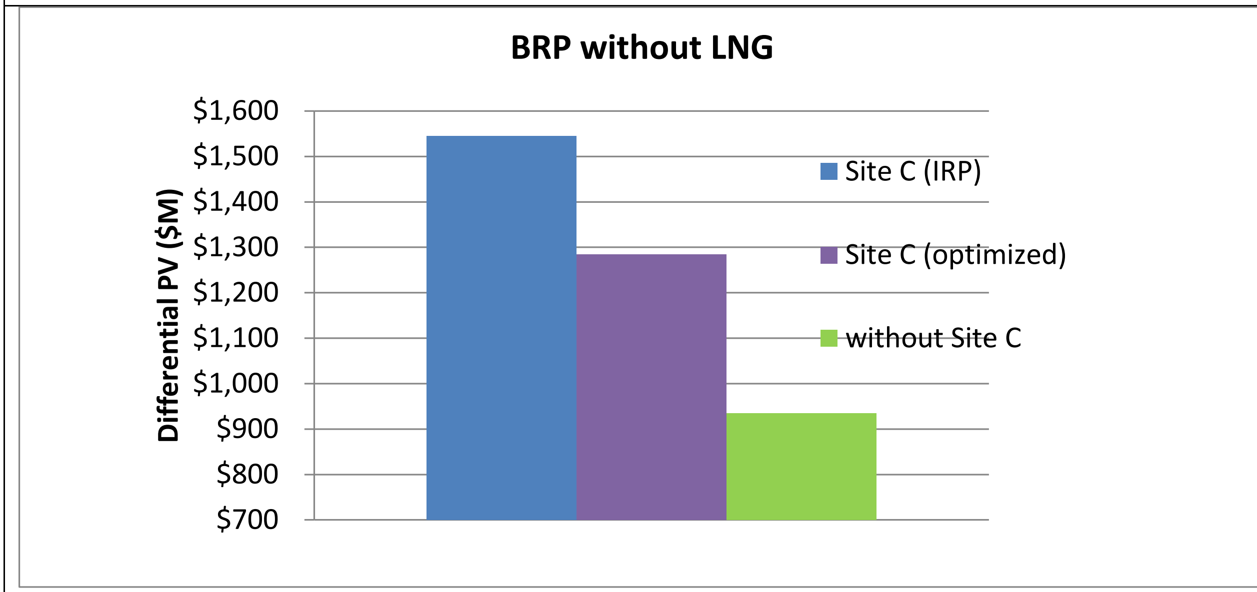


Again, it is important to recall that these curves represent only the cost categories that vary among the different plans. Thus, only their relative values are meaningful.

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.

Figure 11



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

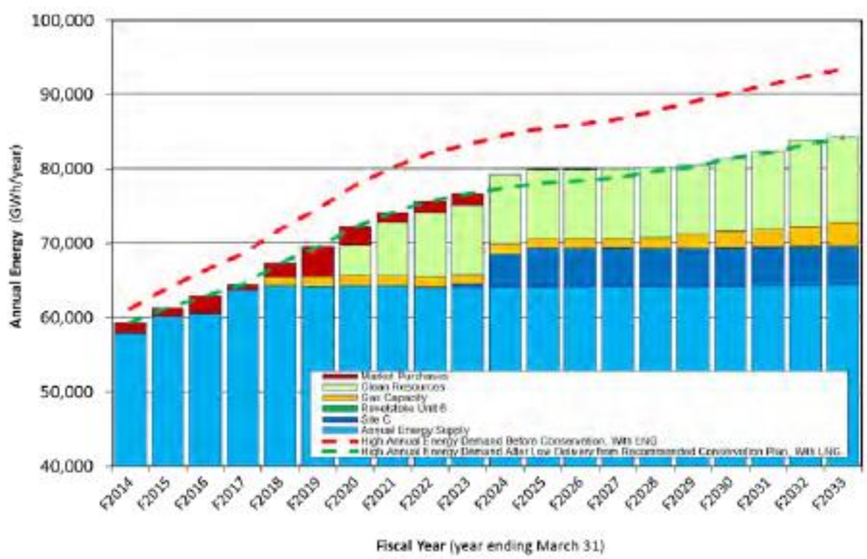
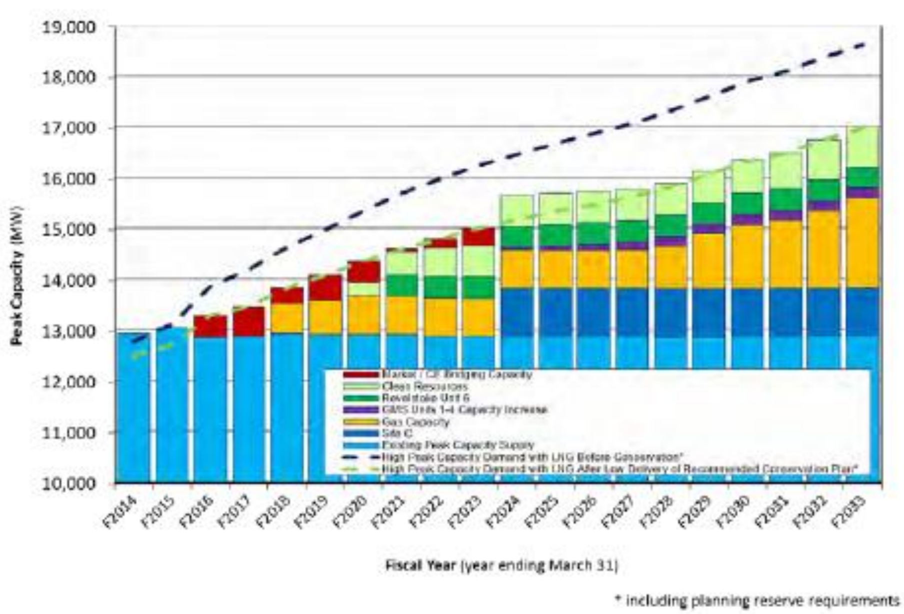


Figure 13. CRP with LNG (Site C, IRP) - Capacity



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 1960 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.[23] 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.

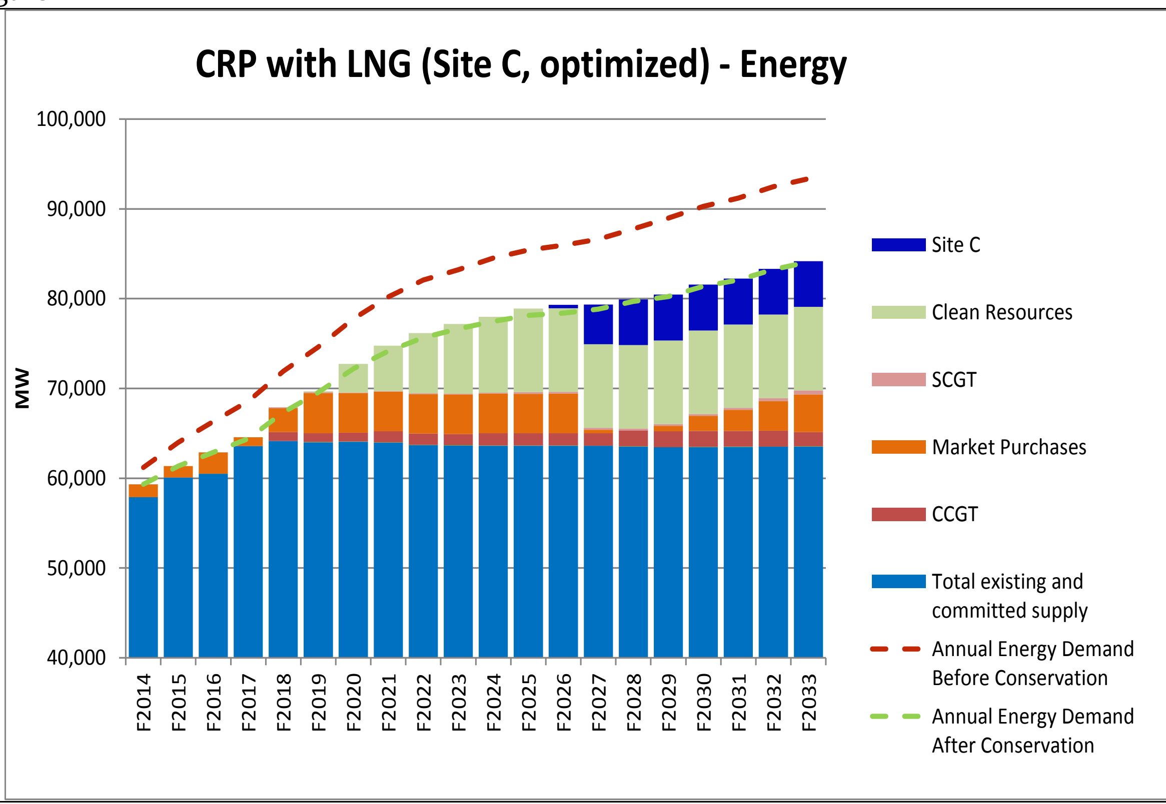
I have also used market energy purchases to limit the amount of more expensive Clean Resources required. In the detailed CRP (with LNG) published in the IRP, market purchases rise to 4,506 GWh in F2019, but then taper off. As the self-sufficiency section of the *CEA* only

[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%.

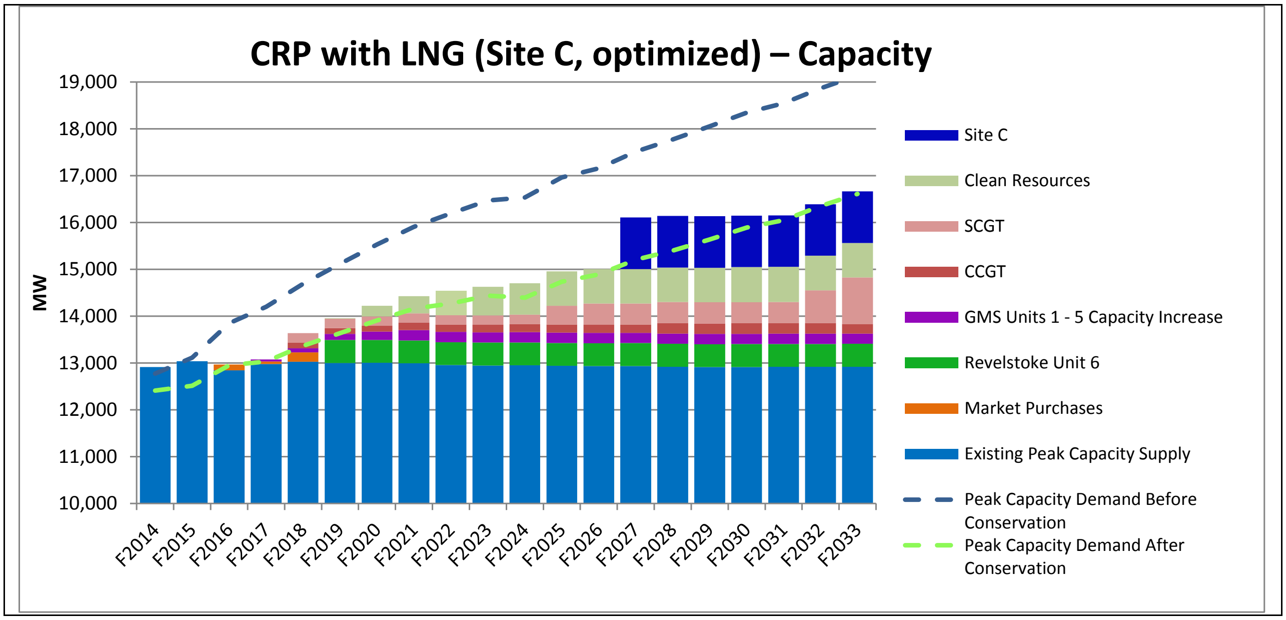
applies to planning under mid-level forecasts,[24] there appears to be no legal obstacle to continuing to use low-cost electricity imports in the CRP. In this and the following portfolios, energy purchases up to, but not exceeding, the level used in BC Hydro's CRP portfolios have been allowed.

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.

Figure 14



[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".

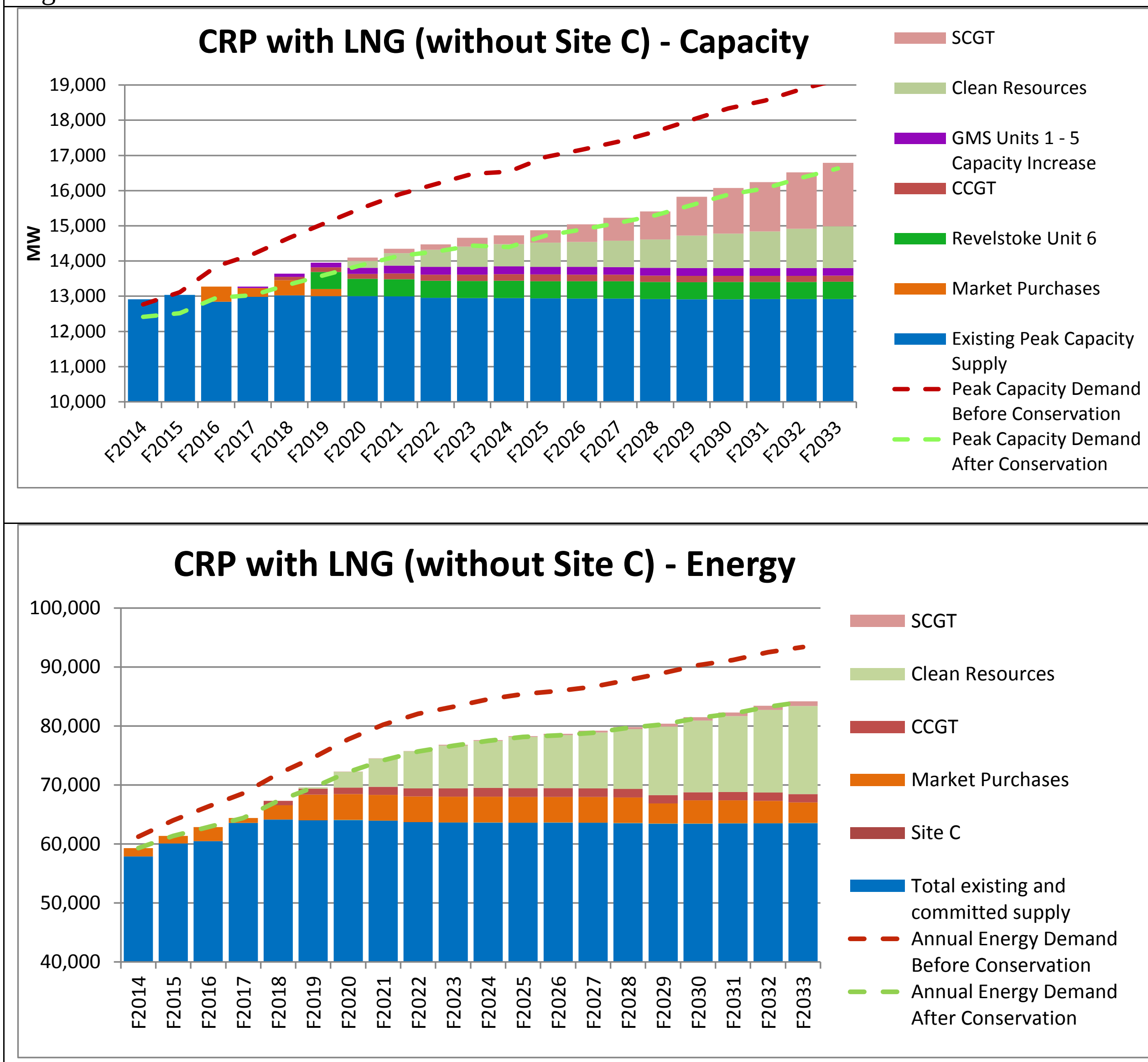


4.2.3. CRP with LNG — without Site C

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.

Figure 15

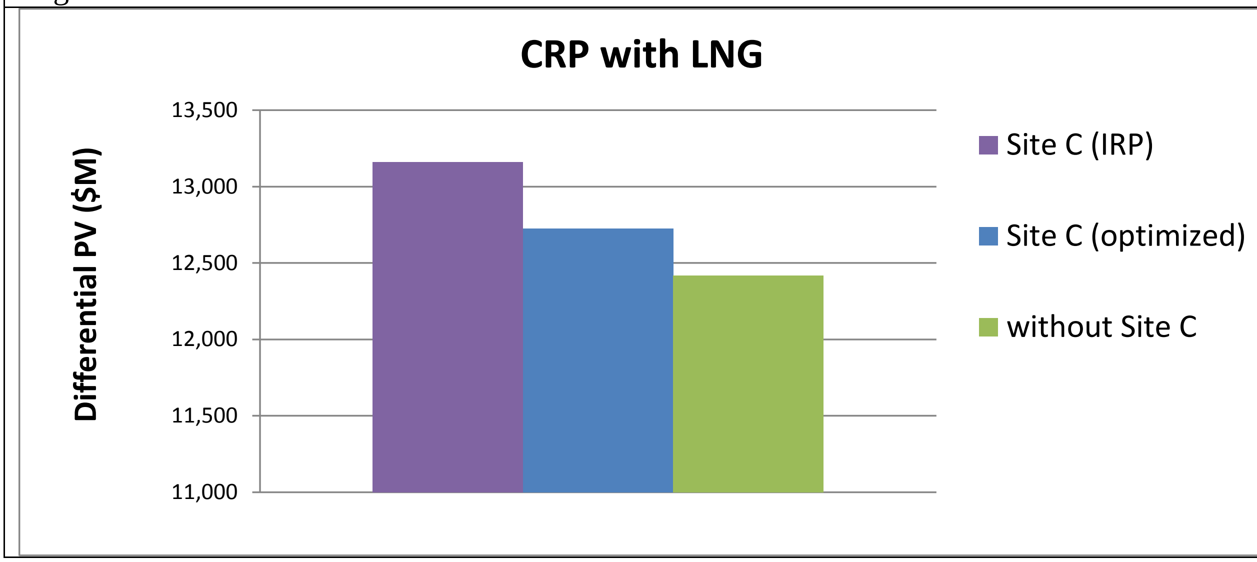


Differential costs are $743 million less than in the original CRP, and are $309 million less than the optimized CRP with Site C. Once again, the primary reasons are the substitution of energy from Site C with energy from combined cycle gas turbines and from purchases, both at a significantly lower cost.

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.[25]

Figure 16



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."[26]

[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.

[26] BC Hydro Rebuttal Evidence, p. 27, line 9.

4.3. Low Growth Resource Plan (LGRP)

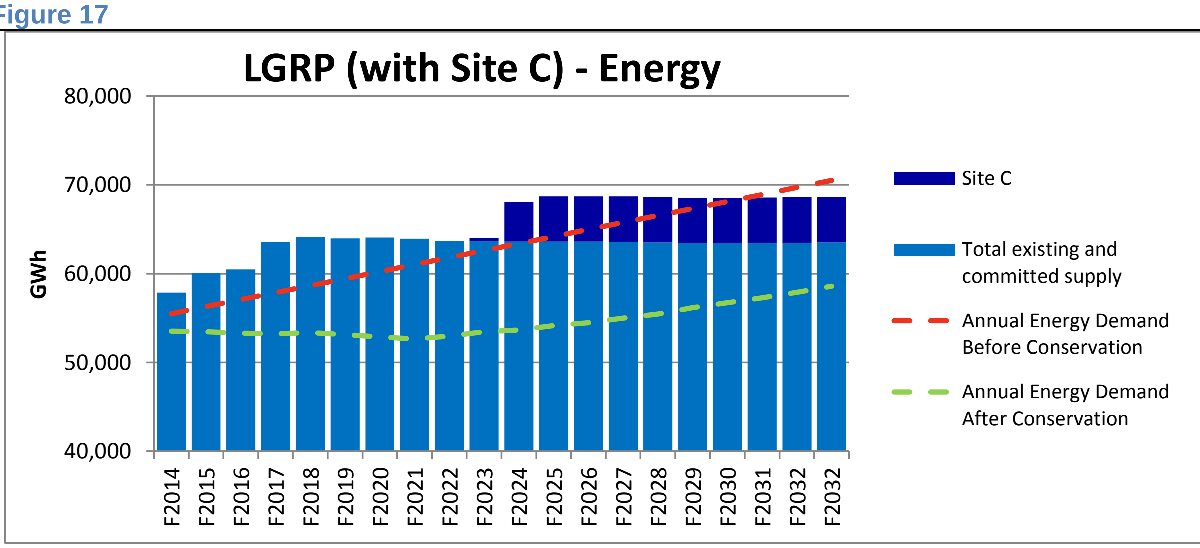
Like most other utilities, in order to quantify the uncertainty in future load growth, BC Hydro prepares a low and high load growth scenario as part of its annual load forecasting exercise. BC Hydro's Base Resource Plan is based on the medium load growth scenario, and its Contingency Resource Plan is 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,[27] and, using these data, it is possible to generate graphs similar to those presented in the IRP.

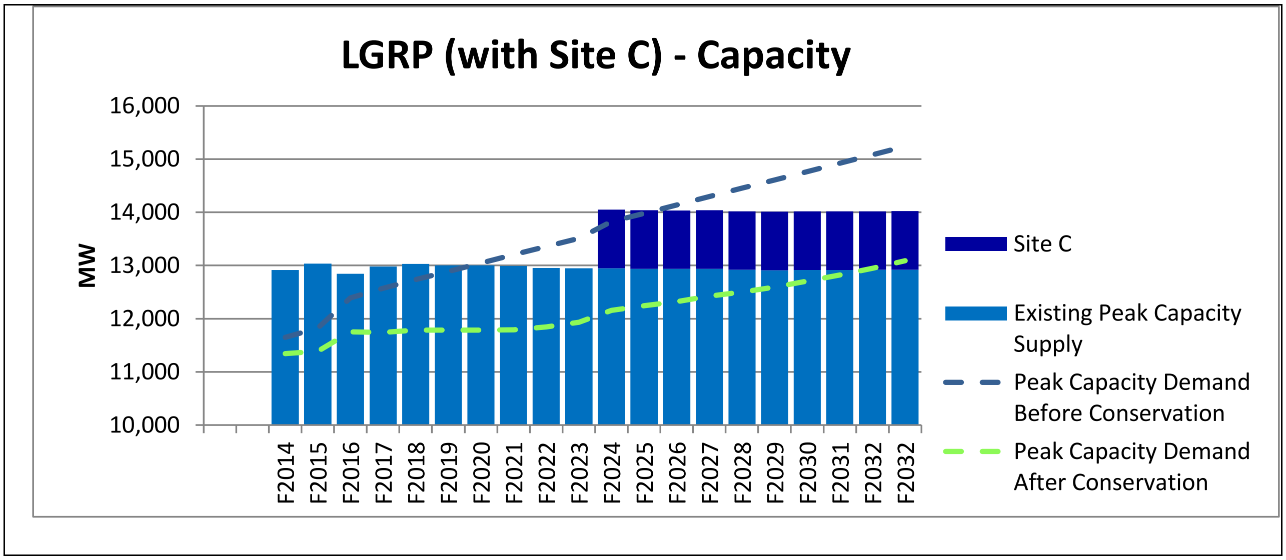
4.3.1. Low Growth Resource Plan (LGRP) without LNG – with Site C

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.

Figure 17



[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!

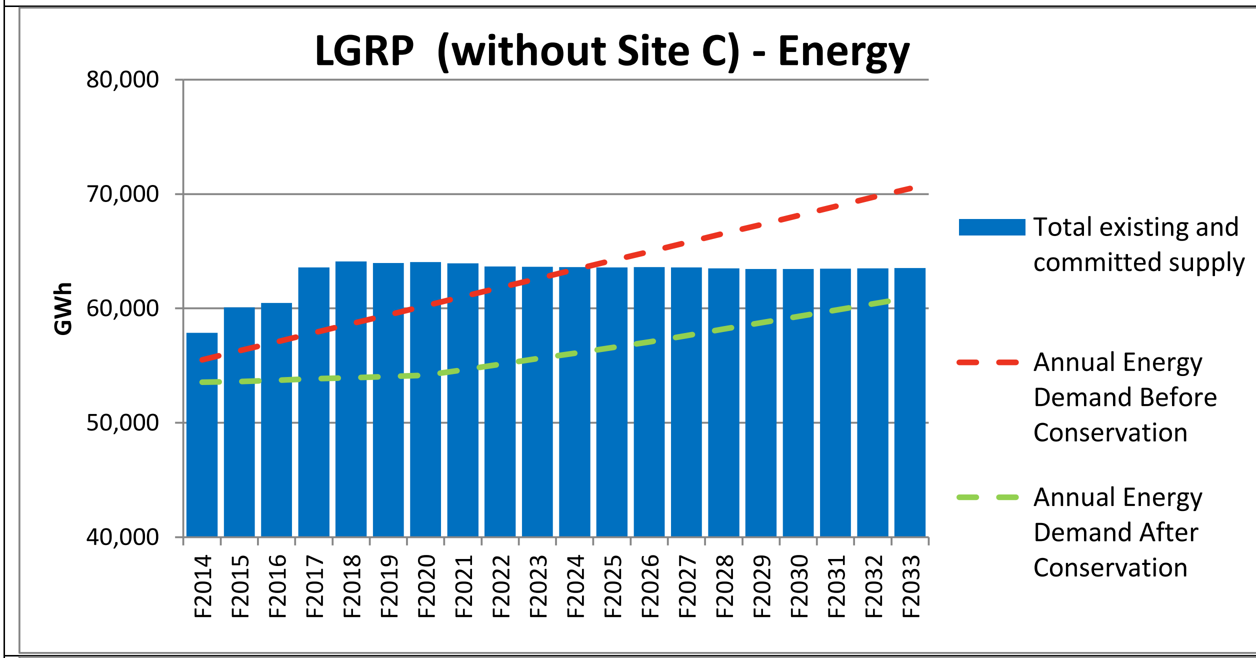
As seen in the lower chart, under the low load growth scenario, the capacity of Site C would remain entirely surplus to peak demand needs after conservation until 2032.

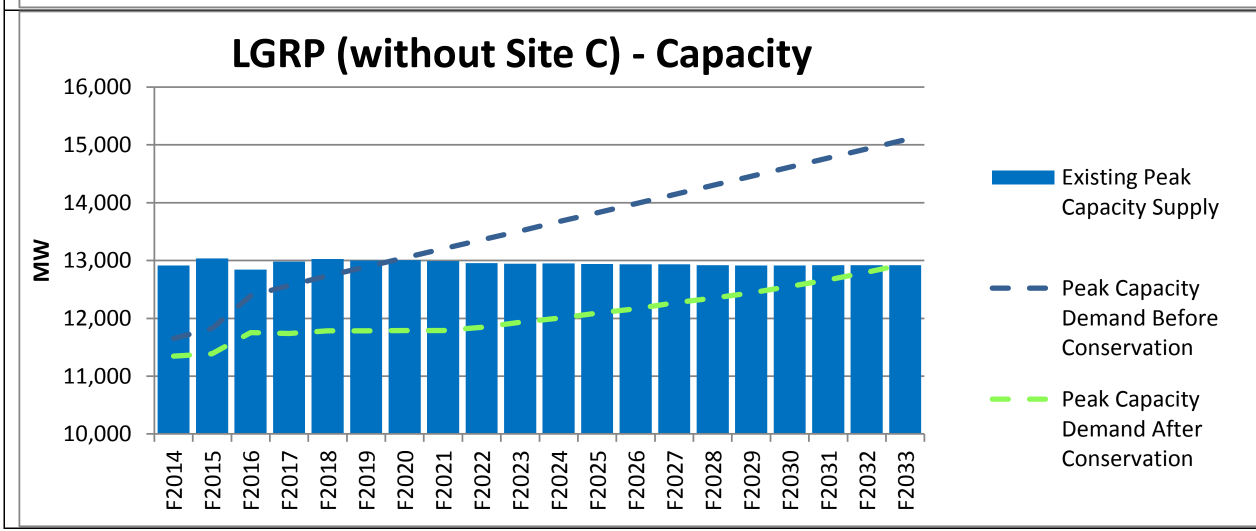
4.3.2. LGRP without LNG – without Site C

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.

Figure 18





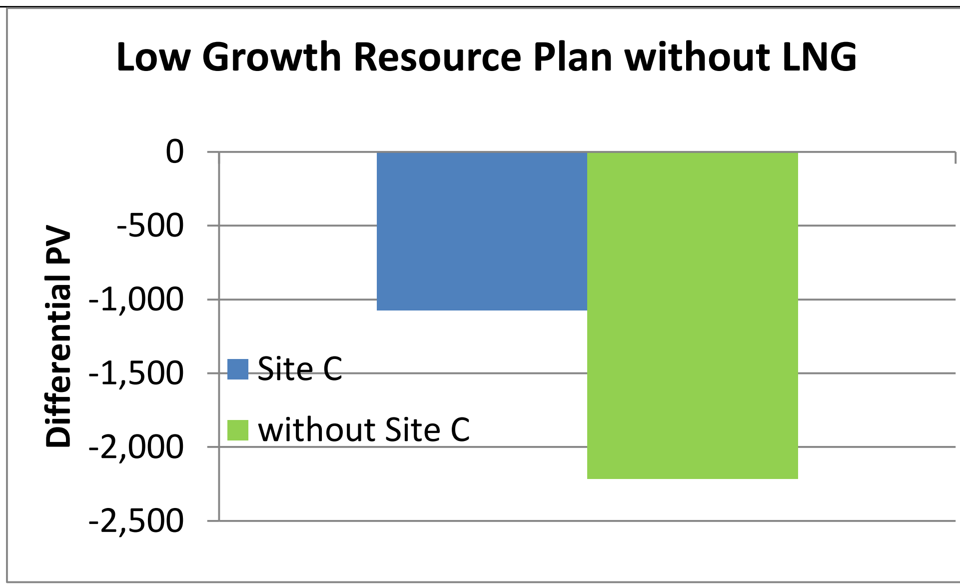
Even with no new generation resources, BC Hydro would still have surplus energy and capacity under this scenario, thanks to the increased contribution of DSM. Depending on the relationship between market prices and the marginal cost of these "negawatt-hours", it may or may not be cost-effective to maintain 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.[28] This finding confirms the similar results of BC Hydro's portfolio analysis, mentioned on page 18, above.

Figure 19



[28] 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.[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 <u>similar sized blocks</u> of energy and capacity provided by alternative resources. [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, **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%.

---

[29] BC Hydro, Site C EIS, p.6-121.

[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).

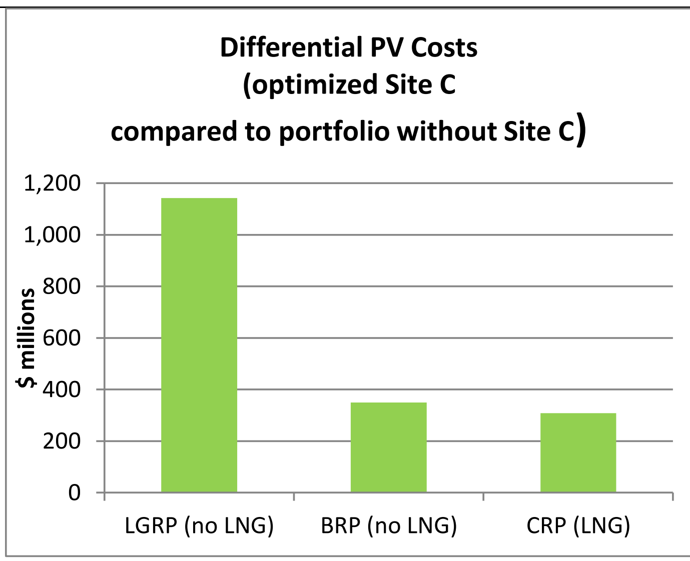
Figure 20

Present value differential costs ($ millions)			
	LGRP (no LNG)	BRP (no LNG)	CRP (LNG)
Site C (IRP)	-1,073	1,545	13,161
Site C (optimized)		1,285	12,726
without Site C	-2,216	935	12,418

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.

Figure 21



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

BRP without LNG (without Site C) - Capacity (MW)

	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	10,182	10,182	10,077	10,072	10,072	10,072	10,072	10,072	10,072	10,072	10,072	10,072	10,072	10,072	10,072	10,072	10,072	10,072	10,072	10,072
Heritage Thermal	946	496	46	46	46	46	46	46	46	46	46	46	46	46	46	46	46	46	46	46
Resource Smart	51	51	51	51	51	51	51	51	51	51	51	51	51	51	51	51	51	51	51	51
Waneta Transaction	256	249	249	249	249	249	249	249	249	249	249	249	249	249	249	249	249	249	249	249
Mica 5	0	465	465	465	465	465	465	465	465	465	465	465	465	465	465	465	465	465	465	465
Mica 6	0	0	460	460	460	460	460	460	460	460	460	460	460	460	460	460	460	460	460	460
Ruskin	0	0	73	76	114	114	114	114	114	114	114	114	114	114	114	114	114	114	114	114
John Hart	0	0	0	127	127	127	127	127	127	127	127	127	127	127	127	127	127	127	127	127
	11,435	11,443	11,421	11,546	11,584	11,584	11,584	11,584	11,584	11,584	11,584	11,584	11,584	11,584	11,584	11,584	11,584	11,584	11,584	11,584
Existing and Committed IPP Resources																				
	667	557	553	547	523	462	426	426	426	151	145	139	134	134	123	123	122	122	122	122
Pre-F06 Call EPAs (excl. Rio Tinto Alcan) F2006 Call	85	86	86	86	86	86	86	86	86	86	86	86	86	86	86	75	73	73	69	69
Standing Offer Program (signed EPAs)	10	11	11	11	11	11	11	11	11	11	11	11	11	11	11	11	10	10	9	9
Bioenergy Call Phase I	67	67	67	67	67	67	54	29	29	29	29	29	29	29	0	0	0	0	0	0
Clean Power Call	86	112	128	141	159	162	162	162	162	162	162	162	162	162	162	162	162	162	162	156
AltaGas Power (NTL)	0	26	31	31	31	31	31	31	31	31	31	31	31	31	31	31	31	31	31	31
Waneta Expansion	0	0	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10
Integrated Power Offer	128	152	165	165	165	165	165	165	82	65	65	41	29	29	21	0	0	0	0	0
Bioenergy Call Phase II	0	15	65	65	65	65	65	65	65	65	65	65	65	65	65	65	65	65	65	65
Conifex	0	21	21	21	21	21	21	21	21	21	21	21	21	21	21	21	21	21	21	21
	1,043	1,047	1,137	1,144	1,138	1,080	1,031	1,006	923	631	625	595	578	578	530	498	494	494	489	483
Future Supply-Side Resources																				
IPP Renewals	16	126	129	133	146	177	202	214	256	539	545	563	574	574	603	624	629	629	634	640
Standing Offer Program	0	0	2	4	6	8	10	12	14	16	18	20	22	24	26	29	31	33	35	37
IBAs	0	0	0	0	0	0	24	24	24	24	24	24	24	24	24	24	24	24	24	24
Revelstoke Unit 6	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	488	488	488
GMS Units 1 - 5 Capacity Increase	0	0	0	0	0	0	0	44	88	132	220	220	220	220	220	220	220	220	220	220
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	125	125	135	140	145
Clean Resources		0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	35	85	151	201
Total Supply Requiring Reserves	12,494	12,616	12,689	12,827	12,874	12,849	12,851	12,884	12,889	12,926	13,016	13,006	13,002	13,004	12,987	13,104	13,142	13,692	13,765	13,822
Reserves																				
14% of Supply Requiring Reserves	-1,749	-1,766	-1,776	-1,796	-1,802	-1,799	-1,799	-1,804	-1,804	-1,810	-1,822	-1,821	-1,820	-1,821	-1,818	-1,835	-1,840	-1,917	-1,927	-1,935
400 MW market reliance	400	400	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
	-1,349	-1,366	-1,776	-1,796	-1,802	-1,799	-1,799	-1,804	-1,804	-1,810	-1,822	-1,821	-1,820	-1,821	-1,818	-1,835	-1,840	-1,917	-1,927	-1,935
Supply Not Requiring Reserves																				
Alcan 2007 EPA	419	419	153	153	153	153	153	153	153	153	153	153	153	153	153	153	153	153	153	153
Market Purchases	0	0	0	0	0	0	0				0	0	0	0	0	0		0	0	0
	419	419	153	153	153	153	153	153	153	153	153	153	153	153	153	153	153	153	153	153
Effective Load Carrying Capability	11,564	11,669	11,066	11,184	11,225	11,203	11,205	11,233	11,238	11,269	11,347	11,338	11,335	11,336	11,322	11,422	11,455	11,928	11,991	12,040
2012 Mid Load Forecast Before DSM	-11,011	-11,222	-11,451	-11,681	-11,971	-12,230	-12,443	-12,613	-12,743	-12,950	-13,125	-13,288	-13,438	-13,609	-13,817	-14,036	-14,258	-14,482	-14,701	-14,915
Future Demand Side Management & Other Measures																				
SMI Theft Reduction	0	0	0	9	17	26	35	43	52	60	68	76	76	76	76	76	76	76	76	76
Voltage and VAR Optimization	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
DSM Option 2 / DSM Target	304	439	638	820	932	1,078	1,224	1,371	1,460	1,519	1,601	1,663	1,743	1,797	1,873	1,939	1,983	2,028	2,057	2,074
Differential DSM 3 to DSM 2				24	50	74	89	93	175	218	228	242	221	221	221	221	221	221	221	221
Industrial Load Curtailment	39	125	210	261	294	313	317	315	315	316	313	317	315	316	315	315	315	319	315	316
Capacity-focused DSM programs	14	44	80	119	133	137	133	135	136	134	135	135	135	137	135	136	135	136	136	135
Time-base rates	11	20	34	43	52	59	78	102	124	148	169	193	196	201	203	207	210	216	216	216
Total Capacity-focussed DSM	64	188	323	423	479	509	529	552	575	598	618	645	645	653	653	658	659	671	666	667
	368	627	961	1276	1477	1687	1877	2058	2261	2395	2515	2626	2685	2747	2823	2894	2939	2996	3020	3038
Surplus / Deficit	921	1074	576	779	731	660	639	678	756	714	736	676	582	475	328	280	136	442	310	162

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	42,048	42,048	42,048	42,048	42,048	42,048	42,048	42,048	42,048	42,048	42,048
Heritage Hydroelectric Non-Firm / Market Allowance	0	0	0	4,100	4,100	4,100	4,100	4,100	4,100	4,100	4,100	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
Waneta Transaction	1,003	874	865	865	865	865	865	865	865	865	865	865	865	865	865	865	865	865	865	865
Mica 5	0	73	145	145	145	145	145	145	145	145	145	145	145	145	145	145	145	145	145	145
Mica 6	0	0	28	56	56	56	56	56	56	56	56	56	56	56	56	56	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
Sub-total	46,056	45,948	46,949	48,425	48,652	48,671	48,671	48,671	48,671	48,671	48,671	48,671	48,671	48,671	48,671	48,671	48,671	48,671	48,671	48,671
Existing and Committed IPP Resources																				
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
Integrated Power Offer	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
Bioenergy Call Phase II	0	109	360	565	565	565	565	565	565	565	565	565	565	565	565	565	565	565	565	565
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
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	6,356
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
Revelstoke Unit 6	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	26	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	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	450	1,100	1,950	2,604
SubTotal	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
Total 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**	**64,425**	**64,885**	**65,665**	**66,580**	**67,300**
Demand - Integrated System Total Gross Requirements																				
2012 Mid Load Forecast Before DSM	-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
Future DSM & Other Measures																				
SMI Theft Reduction	0	0	0	0	65	129	193	256	318	380	442	503	562	562	562	562	562	562	562	562
Voltage and VAR Optimization	38	162	229	273	288	304	314	326	328	329	331	333	334	336	338	339	341	343	345	346
DSM Option 2 / DSM Target	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
Differential DSM 3 to DSM 2	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
SubTotal	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
DSM as % of load growth		170%	129%	106%	80%	78%	77%	79%	80%	79%	78%	77%	77%	76%	73%	70%	67%	65%	63%	61%
Annual Energy Demand After Conservation	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
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

CRP with LNG (without Site C) – Capacity (MW)

	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	10,182	10,182	10,077	10,072	10,072	10,072	10,072	10,072	10,072	10,072	10,072	10,072	10,072	10,072	10,072	10,072	10,072	10,072	10,072	10,072
Heritage Thermal	946	496	46	46	46	46	46	46	46	46	46	46	46	46	46	46	46	46	46	46
Resource Smart	51	51	51	51	51	51	51	51	51	51	51	51	51	51	51	51	51	51	51	51
Waneta Transaction	256	249	249	249	249	249	249	249	249	249	249	249	249	249	249	249	249	249	249	249
Mica 5	0	465	465	465	465	465	465	465	465	465	465	465	465	465	465	465	465	465	465	465
Mica 6	0	0	460	460	460	460	460	460	460	460	460	460	460	460	460	460	460	460	460	460
Ruskin	0	0	73	76	114	114	114	114	114	114	114	114	114	114	114	114	114	114	114	114
John Hart	0	0	0	127	127	127	127	127	127	127	127	127	127	127	127	127	127	127	127	127
	11,435	11,443	11,421	11,546	11,584	11,584	11,584	11,584	11,584	11,584	11,584	11,584	11,584	11,584	11,584	11,584	11,584	11,584	11,584	11,584
Existing and Committed IPP Resources																				
	667	557	553	547	523	462	426	426	426	151	145	139	134	134	123	123	122	122	122	122
Pre-F06 Call EPAs (excl. Rio Tinto Alcan) F2006 Call	85	86	86	86	86	86	86	86	86	86	86	86	86	86	86	75	73	73	69	69
Standing Offer Program (signed EPAs)	10	11	11	11	11	11	11	11	11	11	11	11	11	11	11	11	10	10	9	9
Bioenergy Call Phase I	67	67	67	67	67	67	54	29	29	29	29	29	29	29	0	0	0	0	0	0
Clean Power Call	86	112	128	141	159	162	162	162	162	162	162	162	162	162	162	162	162	162	162	156
AltaGas Power (NTL)	0	26	31	31	31	31	31	31	31	31	31	31	31	31	31	31	31	31	31	31
Waneta Expansion	0	0	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10
Integrated Power Offer	128	152	165	165	165	165	165	165	82	65	65	41	29	29	21	0	0	0	0	0
Bioenergy Call Phase II	0	15	65	65	65	65	65	65	65	65	65	65	65	65	65	65	65	65	65	65
Conifex	0	21	21	21	21	21	21	21	21	21	21	21	21	21	21	21	21	21	21	21
	1,043	1,047	1,137	1,144	1,138	1,080	1,031	1,006	923	631	625	595	578	578	530	498	494	494	489	483
Future Supply-Side Resources																				
IPP Renewals	16	126	129	133	146	177	202	214	256	539	545	563	574	574	603	624	629	629	634	640
Standing Offer Program	0	0	2	4	6	8	10	12	14	16	18	20	22	24	26	29	31	33	35	37
IBAs	0	0	0	0	0	0	24	24	24	24	24	24	24	24	24	24	24	24	24	24
Revelstoke Unit 6	0	0	0	0	0	488	488	488	488	488	488	488	488	488	488	488	488	488	488	488
GMS Units 1 - 5 Capacity Increase	0	0	0	44	88	132	176	220	220	220	220	220	220	220	220	220	220	220	220	220
SCGT	0	0	0	0	0	0	100	125	150	250	250	350	500	650	800	1100	1300	1400	1600	1800
CCGT	0	0	0	0	100	130	140	170	170	180	190	190	190	185	180	180	175	175	175	175
Clean Resources	0	0	0	0	0	0	192	353	490	575	634	686	710	749	805	923	979	1042	1114	1183
	16	126	131	181	340	935	1332	1606	1812	2292	2369	2541	2728	2914	3146	3588	3846	4011	4290	4567
Total Supply Requiring Reserves (d) = a + b + c	12,494	12,616	12,689	12,871	13,062	13,599	13,947	14,196	14,319	14,507	14,578	14,720	14,890	15,076	15,260	15,670	15,924	16,089	16,363	16,634
Reserves																				
14% of Supply Requiring Reserves	-1,749	-1,766	-1,776	-1,802	-1,829	-1,904	-1,953	-1,987	-2,005	-2,031	-2,041	-2,061	-2,085	-2,111	-2,136	-2,194	-2,229	-2,252	-2,291	-2,329
400 MW market reliance	400	400	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
	-1,349	-1,366	-1,776	-1,802	-1,829	-1,904	-1,953	-1,987	-2,005	-2,031	-2,041	-2,061	-2,085	-2,111	-2,136	-2,194	-2,229	-2,252	-2,291	-2,329
Supply Not Requiring Reserves																				
Alcan 2007 EPA	419	419	153	153	153	153	153	153	153	153	153	153	153	153	153	153	153	153	153	153
Market Purchases	0	0	435	250	425	200	0	0	0	0	0	0	0	0	0	0	0	0	0	0
	419	419	588	403	578	353	153	153	153	153	153	153	153	153	153	153	153	153	153	153
Effective Load Carrying Capability	11,564	11,669	11,501	11,472	11,811	12,048	12,147	12,362	12,467	12,629	12,690	12,812	12,958	13,119	13,276	13,630	13,847	13,989	14,225	14,458
2012 High Load Forecast Before DSM	-11,421	-11,746	-12,074	-12,396	-12,832	-13,189	-13,438	-13,668	-13,823	-14,087	-14,139	-14,532	-14,721	-14,923	-15,178	-15,456	-15,747	-15,946	-16,231	-16,469
Expected LNG Load							-120	-240	-360	-360	-360	-360	-360	-360	-360	-360	-360	-360	-360	-360
2012 High Load Forecast Before DSM w LNG	-11,421	-11,746	-12,074	-12,396	-12,832	-13,189	-13,558	-13,908	-14,183	-14,447	-14,499	-14,892	-15,081	-15,283	-15,538	-15,816	-16,107	-16,306	-16,591	-16,829
Future Demand Side Management & Other Measures																				
SMI Theft Reduction	0	0	0	9	17	26	35	43	52	60	68	76	76	76	76	76	76	76	76	76
Voltage and VAR Optimization	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
DSM Option 2 / DSM Target - Low Deliverability	294	410	574	712	779	872	965	1,058	1,124	1,161	1,228	1,265	1,328	1,361	1,428	1,462	1,495	1,529	1,551	1,564
Differential DSM 3 to DSM 2				24	50	74	89	93	175	218	228	242	221	221	221	221	221	221	221	221
Industrial Load Curtailment	39	125	210	261	294	313	317	315	315	316	313	317	315	316	315	315	315	319	315	316
Capacity-focused DSM programs	14	44	80	119	133	137	133	135	136	134	135	135	135	137	135	136	135	136	136	135
Time-base rates	11	20	34	43	52	59	78	102	124	148	169	193	196	201	203	207	210	216	216	216
	358	598	897	1168	1324	1481	1618	1745	1925	2037	2142	2228	2270	2311	2378	2417	2451	2497	2514	2528
Surplus / Deficit	501	521	324	244	304	340	207	199	210	219	333	148	147	147	116	230	192	180	148	157

CRP with 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	42,048	42,048	42,048	42,048	42,048	42,048	42,048	42,048	42,048	42,048	42,048
Heritage Hydroelectric Non-Firm / Market Allowance	0	0	0	4,100	4,100	4,100	4,100	4,100	4,100	4,100	4,100	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
Waneta Transaction	1,003	874	865	865	865	865	865	865	865	865	865	865	865	865	865	865	865	865	865	865
Mica 5	0	73	145	145	145	145	145	145	145	145	145	145	145	145	145	145	145	145	145	145
Mica 6	0	0	28	56	56	56	56	56	56	56	56	56	56	56	56	56	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
Sub-total	46,056	45,948	46,949	48,425	48,652	48,671	48,671	48,671	48,671	48,671	48,671	48,671	48,671	48,671	48,671	48,671	48,671	48,671	48,671	48,671
Existing and Committed IPP Resources																				
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
Integrated Power Offer	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
Bioenergy Call Phase II	0	109	360	565	565	565	565	565	565	565	565	565	565	565	565	565	565	565	565	565
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	64,135	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
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	6,356
Standing Offer Program	0	0	27	52	80	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
Revelstoke Unit 6	0	0	0	0	0	26	26	26	26	26	26	26	26	26	26	26	26	26	26	26
SCGT	0	0	0	0	0	0	44	55	66	110	110	153	219	285	350	482	569	613	701	788
CCGT	0	0	0	0	788	1,025	1,104	1,340	1,340	1,419	1,498	1,498	1,498	1,459	1,419	1,419	1,380	1,380	1,380	1,380
Clean Resources	0	0	0	0	0	200	2,677	4,826	6,315	7,258	8,008	8,658	8,958	9,458	10,158	11,620	12,159	12,885	14,006	14,963
Market Purchases	1,436	1,262	2,384	841	2,400	4,350	4,350	4,350	4,350	4,350	4,350	4,350	4,350	4,350	4,350	3,400	3,900	3,900	3,800	3,500
SubTotal	1,524	1,916	3,507	2,040	4,513	7,277	10,184	12,747	14,567	17,899	19,067	20,067	20,619	21,309	22,279	23,385	24,748	25,627	26,834	27,657
Total Supply	**59,311**	**61,349**	**62,874**	**64,417**	**67,323**	**69,584**	**72,266**	**74,548**	**75,781**	**76,803**	**77,606**	**78,286**	**78,661**	**79,175**	**79,820**	**80,386**	**81,483**	**82,279**	**83,413**	**84,184**
2012 High Load Forecast Before DSM	-61,207	-64,003	-66,326	-68,569	-71,902	-74,610	-76,745	-78,203	-79,060	-80,234	-81,516	-82,401	-82,954	-83,617	-84,768	-85,974	-87,280	-88,192	-89,476	-90,366
Expected LNG Load							-1,000	-2,000	-3,000	-3,000	-3,000	-3,000	-3,000	-3,000	-3,000	-3,000	-3,000	-3,000	-3,000	-3,000
2012 High Load Forecast Before DSM with LNG	-61,207	-64,003	-66,326	-68,569	-71,902	-74,610	-77,745	-80,203	-82,060	-83,234	-84,516	-85,401	-85,954	-86,617	-87,768	-88,974	-90,280	-91,192	-92,476	-93,366
Annual Energy Demand Before Conservation	61,207	64,003	66,326	68,569	71,902	74,610	77,745	80,203	82,060	83,234	84,516	85,401	85,954	86,617	87,768	88,974	90,280	91,192	92,476	93,366
Future DSM & Other Measures																				
SMI Theft Reduction	0	0	0	65	129	193	256	318	380	442	503	562	562	562	562	562	562	562	562	562
Voltage and VAR Optimization	38	162	229	273	288	304	314	326	328	329	331	333	334	336	338	339	341	343	345	346
DSM Option 2 / DSM Target low deliverability	1,857	2,495	3,224	3,813	4,167	4,574	4,980	5,385	5,688	5,810	6,221	6,357	6,671	6,872	7,181	7,839	8,015	8,199	8,321	8,389
Differential DSM 3 to DSM 2				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
SubTotal	1,895	2,657	3,453	4,151	4,584	5,071	5,550	6,029	6,396	6,581	7,055	7,252	7,567	7,770	8,081	8,740	8,918	9,104	9,228	9,297
DSM as % of load growth		95%	67%	56%	43%	38%	34%	32%	31%	30%	30%	30%	31%	31%	30%	31%	31%	30%	30%	29%
Annual Energy Demand After Conservation	59,312	61,346	62,873	64,418	67,318	69,539	72,195	74,174	75,664	76,653	77,461	78,149	78,387	78,847	79,687	80,234	81,362	82,088	83,248	84,069
Total gas-fired generation	3,520	3,520	3,520	3,520	4,308	4,545	4,668	4,915	4,926	5,049	5,127	5,171	5,237	5,263	5,290	5,421	5,469	5,513	5,601	5,688
% gas-fired generation	6.1%	5.9%	5.8%	5.5%	6.6%	7.0%	6.9%	7.0%	6.9%	7.0%	7.0%	7.0%	7.0%	7.0%	7.0%	7.0%	7.0%	7.0%	7.0%	7.0%
Surplus / Deficit (GWh)	**-1**	**3**	**1**	**-1**	**5**	**45**	**71**	**374**	**117**	**150**	**145**	**137**	**274**	**328**	**133**	**152**	**121**	**191**	**165**	**115**

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]

In 1997, he advised the Standing Committee on the Economy and Labour of the Quebec National Assembly in its oversight hearings concerning Hydro-Quebec. In 2001, he authored a major study on the implications of electricity market restructuring for hydropower developments, entitled *Restructured Rivers: Hydropower in the Era of Competitive Energy Markets*. In 2005, he advised the Federal Review Commission studying the Eastmain 1A/Rupert Diversion hydro project with respect to project justification. Later, he drafted a submission to this same panel on behalf of the affected Cree communities of Nemaska, Waskaganish and Chisasibi.

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.

[31] J. Litchfield, L. Hemmingway, and P. Raphals. 1994. *Integrated resources planning and the Great Whale Public Review*. Background paper no. 7, Great Whale Public Review Support Office, 115 pp. *(also published in French).*

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.