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INFORMATION RELEASE – BCUC responds to the Provincial Government's additional questions in the Inquiry Respecting Site C
November 23, 2017

Vancouver – The British Columbia Utilities Commission (BCUC) has responded to the joint letter from the Ministry of Energy, Mines and Petroleum Resources and Ministry of Finance seeking additional information in the BCUC's Inquiry respecting Site C. The BCUC's response is attached to this information release.

The BCUC's Inquiry into Site C was initiated by Order in Council No. 244 on August 2, 2017 and was completed with the issuance of the Inquiry Panel's Final Report on November 1, 2017. The Final Report, and all information submitted during the course of the Inquiry is publically available at www.sitecinquiry.com.

The BCUC is a regulatory agency responsible for oversight of energy utilities and compulsory auto insurance in the province of British Columbia. It is the BCUC's role to balance the interests of customers with the interests of the businesses we regulate. The BCUC carries out fair and transparent reviews of matters within its jurisdiction and considers public input where public interest is impacted.

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November 23, 2017

Sent via email

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Re: British Columbia Hydro and Power Authority - British Columbia Utilities Commission Inquiry Respecting Site C – Project No. 1598922

Dear Dave Nikolejsin and Lori Wanamaker:

The Deputy Ministers' letter of November 15, 2017 poses a series of questions to the Commission regarding its Final Report on the Site C Inquiry, which was initiated by the Lieutenant Governor by Order in Council 244. The Commission thanks the Deputy Ministers for their inquiry and sets out its response below, trusting that any additional clarity or amplification of the messages in the Final Report will assist the government in its decision regarding Site C.

Sincerely,

Original signed by:

David Morton
Chair and Chief Executive Officer

DM/kbb
Enclosure

Introduction

The Inquiry initiated by Order in Council (OIC) 244 requested that the Commission evaluate the cost to BC Hydro ratepayers of continuing, suspending or terminating construction of the Site C dam. In its Final Report, the Commission drew two overall conclusions:

- The cost to ratepayers of suspending construction would be significantly higher than either continuing or terminating the project, to the tune of $3.6 billion.[1] In addition, there are significant risks that it would not be possible to restart the project due to permitting and other issues.
- The cost to ratepayers of continuing or terminating construction is similar,[2] given the assumptions that the Commission finds to be most reasonable. Both alternatives also have risks which may cause one or the other to be more costly to ratepayers either in the short-term or over a longer period.

Many of the questions posed in the Deputy Ministers' letter, in one way or another, relate to the estimates underlying these conclusions. We believe it will be helpful to provide some background and context before addressing the specific questions.

In reaching its conclusions, the Commission was required to estimate the costs of each of the three options, and in the case of termination, the cost of the alternative energy that might be required. It is important to recognize that each estimate comes with a degree of uncertainty. For example, when considering the cost of terminating the Site C project, the Commission found, based on information from BC Hydro and Deloitte, that costs could range from $750 million to $2.3 billion.[3] In order to make a comparison between the options, the Commission chose a reasonable "point estimate" of $1.8 billion based on BC Hydro's P90 estimate.[4] But it would be quite possible, based on the information available to conclude that the cost of termination could be up to a billion dollars less, or half a billion dollars more. Nonetheless, in spite of this uncertainty, it was quite reasonable for the Commission to conclude that the option of suspending the project, estimated to be $3.6 billion more than either continuing or terminating construction, would be significantly more expensive for ratepayers.

By comparison, the estimated costs to ratepayers of continuing or terminating construction, at $2.852 billion and $3.147 billion respectively,[5] were so close that it would be unreasonable for the Commission to draw a meaningful distinction between them. Given the range of estimates to terminate the project ($750 million to $2.3 billion) an even larger difference between the estimated costs to continue or to terminate would have resulted in the Commission drawing the same conclusion they were similar.

To further illustrate how using point estimates for input assumptions masks the potential variability of assumptions, consider the original Site C completion costs. The original estimate of $8.35 billion was based on a

[1] BCUC Site C Inquiry Respecting Site C Executive Summary (Executive Summary), p. 3.
[2] BCUC Site C Inquiry Respecting Site C Final Report (Final Report), p. 187.
[3] Final Report p. 128.
[4] This is BC Hydro's P90 estimate, which should only have a 10% chance of being exceeded.
[5] Final Report, Errata, p. 10 of 11.

Class 3 estimate, which means that the expected accuracy range is from 20% under the budgeted amount to 30% over the budgeted amount – in this case a variance of $4.2 billion.[6]

Similarly, some of the costs associated with the Illustrative Alternative Portfolio are highly uncertain. Costs of acquiring wind generation equipment post 2025 for example, are estimates of future costs and, as such, may not share the accuracy level of a Class 3 estimate.

Accordingly, in order to rely on a numeric analysis of the costs of various options, the differences in results should be greater than the amount of uncertainty in the input assumptions. In the Inquiry, BC Hydro calculated the incremental cost to ratepayers of terminating the Site C project – including the cost of an alternative portfolio – compared to the cost of completing, to be in the range of $6.2 billion to $11.1 billion. If this amount could be substantiated, it would provide a compelling case to continue. However, based on the evidence available to the Inquiry we were unable to verify these amounts.[7]

That said, the estimates provided in the Final Report are based on many assumptions the Commission was required to make based on the information available to it during the Inquiry. To assist the government in its decision-making, the Commission included in the Final Report some sensitivity analyses to show how the cost estimates would change if different assumptions were applied. An example of this is the forecast for energy demand.

The Commission has found that the forecast of energy demand is most likely to be at BC Hydro's "low load" or lower, based on available information, government policies in place and other factors. Should the government undertake future policy changes resulting in an increase in demand as high as BC Hydro's high load forecast, the cost of Site C would be more attractive by $796 million.[8] Likewise, the Commission estimates that Site C will cost $10 billion to complete. Should the government estimate that the project will end up costing $12 billion, the present value of the overall cost to ratepayers of Site C would be higher by $646 million.

In the two examples just described, the difference in the estimates caused by changing the assumptions is less than $1 billion. While this is a significant sum, recall that the estimate of termination costs could vary by that same figure.

The Commission concluded based on its findings, that the cost to ratepayers of continuing or terminating the Site C project is similar. The Commission concedes that the Government might take a different view on one or more of these assumptions, and the sensitivity analysis already provided in the Final Report should allow it to adequately evaluate the consequential effect of a change on the estimated cost to ratepayers. However, the Commission cautions that it would require a very significant difference between the estimates to conclude reliably that one would be more expensive than the other.

In addition to the evaluation of ratepayer costs, the OIC requested that the Commission advise on the broader implications of the three options under consideration. The Final Report stated:

[6] American Association of Cost Engineers, Cost Estimate Classification System – As Applied in Engineering, Procurement and Construction for the Process Industries.
[7] Exhibit F1-1, pp. 66–67 and 96–97.
[8] Executive Summary, p. 17.

> We have not been asked to make recommendations or to identify which option has the highest cost to ratepayers or more significant implications than others. Nevertheless, we have provided our view that not only is the suspension scenario the greatest cost to ratepayers of the three scenarios, it also has other negative implications.
>
> We take no position on which of the termination or completion scenarios has the greatest cost to ratepayers. The Illustrative Alternative Portfolio we have analyzed, in the low-load forecast case, has a similar cost to ratepayers as Site C. If Site C finishes further over budget, it will tend to be more costly than the Illustrative Alternative Portfolio is for ratepayers. If a higher load forecast materializes, the cost to ratepayers for Site C will be less than the Illustrative Alternative Portfolio.
>
> We have provided a discussion of the risk implications of each alternative in order to assist in the evaluation.[9]

We trust that the information in the Final Report, including the discussion of risk, and the results of the province-wide Community Input Sessions and First Nations Input Sessions, will provide useful guidance to the government beyond the question of cost.

[9] Final Report, p. 187.

Question 1: Inclusion of Site C sunk/termination costs

The Deputy Ministers ask:

> *Did the Commission include sunk costs (the estimated $2.1 billion that has been spent to date on the project) and termination costs (the $1.8 billion determined by the Commission) in comparing the costs to ratepayers of completing Site C against the costs of pursuing an alternative portfolio of generation resources?*

Response

The Commission did not include sunk costs in the analysis of ratepayer impact for either Site C or the Illustrative Alternate Portfolio of generation resources. The costs assumed in this analysis were, in both cases, only costs incurred from January 2018 onward. These costs include the termination costs of Site C which are included in the ratepayer impact of the Illustrative Alternative Portfolio.

The Final Report states:

> In order to evaluate the cost to ratepayers of the termination case, and compare that rate impact to the cost of completing Site C, we compare the cost to ratepayers of the energy for the alternative portfolio to the cost of completing Site C from January 1, 2018. The sunk costs of $2.1 billion, which include the Site C regulatory account balance of approximately $0.5 billion, must be recovered in both scenarios. Accordingly, we do not consider the rate impact of the sunk costs in the termination scenario. [10]

The ratepayer impact analysis identifies the present value (PV) of the costs to ratepayers of Site C compared to an Illustrative Alternative Portfolio. The costs are modelled as a cost of service that is recovered in a revenue requirement for the utility. The amounts are calculated annually for seventy years and are discounted (in a net present value [NPV] Analysis) to F2018 dollars. Thus we characterize the cost to ratepayers as the NPV of the seventy-year rate impact.

It is important to note that this does not necessarily reflect the same bill impact as would be faced by an individual ratepayer. That analysis would require further input assumptions, including the number of ratepayers that the revenue requirement is being collected from each year.

[10] Final Report, p. 163.

This treatment is illustrated in the tables on page 167 of the Site C Final Report:

Table 1: Site C Final Report, Tables 39 and 40[11]

Output: Low LF - Alternative Portfolio				
A	Site C Termination Cost (F$18)	$	1,395	million
B	Alternative Portfolio Cost (F$18)	$	2,539	million
C	Surplus Energy Sale (F$18)	$	(788)	million
D	Total Rate Impact (A+B+C)	$	3,147	million

Output: Low LF - Site C				
A	Sunk Costs (F$18)	$	2,100	million
B	Site C Cost to Complete (F$18)	$	4,391	million
C	Flexibility Credit (F$18)	$	(66)	million
D	Surplus Energy Sales (F$18)	$	(1,473)	million
E	Total Rate Impact (B+C+D)	$	2,852	million

In the table above, the $1.395 billion for "Site C Termination Costs" represents the PV of the $1.8 billion of Site C termination costs amortized over 30 years.

Table 2: Rate Impact ($ million) of Site C compared to the Illustrative Alternative Portfolio

	Site C	Illustrative Alternative Portfolio
As provided in the Final Report Errata • Ratepayer impact	$2, 852 million	$3, 147 million[12]

If sunk costs are included, the ratepayer impact of both the continue and terminate options would be affected. If the same amortization period was chosen the effect would be the same for each alternative. We discuss the issue of amortization period for both sunk and termination costs further in our response to question 3.

The Deputy Ministers also ask:

> *We were not able to determine whether the sensitivity analysis included on Page 17 of the report's executive summary includes sunk costs and termination costs consistently. If it does not,*

[11] Final Report, p. 167, as updated by A-25 errata.

[12] In a letter dated November 16, 2017, BC Hydro identified an additional errata related to application of inflation factors and discount rates which would reduce the PV cost of the Illustrative Alternative Portfolio by $60 million. The Final Report was not adjusted for this subsequent errata on the grounds of materiality.

could the Commission advise on how including these sunk and termination costs might change the cost to ratepayers and the unit energy cost (UEC) in both scenarios?

Response

The calculation of the Unit Energy Cost differs from the calculation of cost to ratepayers. The Panel found that there is no generally accepted definition of "unit energy cost." In the Inquiry, BC Hydro stated that "Unit Energy Cost simply expresses the cost for a resource by its levelized annual cost per unit of energy produced." [13]

The term "levelized cost of energy" or "levelized cost of electricity" (both often referred to as LCOE), are in general use in the industry to compare the costs of energy projects. For example, the US Energy Information Administration (EIA) describes LCOE as follows:

> Levelized cost of electricity (LCOE) is often cited as a convenient summary measure of the overall competitiveness of different generating technologies. It represents the per-kilowatt hour cost (in discounted real dollars) of building and operating a generating plant over an assumed financial life and duty cycle. Key inputs to calculating LCOE include capital costs, fuel costs, fixed and variable operations and maintenance (O&M) costs, financing costs, and an assumed utilization rate for each plant type. …[14]

In the Preliminary Report, the Panel defined "unit energy cost" as: ***"Unit Energy Cost*** simply expresses the cost for a resource by its levelized annual cost per unit of energy produced."[15]

There were no submissions received on this issue, and in the Final Report the Panel stated:

> The Panel therefore confirms the unit energy cost definition proposed in the Preliminary Report, that the Unit Energy Cost simply expresses the cost for a resource by its levelized annual cost per unit of energy produced. …
>
> **Given the definition of UEC, the Panel finds it inappropriate that the unit energy cost be adjusted for sunk costs** [i.e. that the sunk costs be added to Site C cost to complete or to the Alternative Portfolio costs, as they are sunk so only future costs matter] **and termination costs** [i.e. that the termination costs be added to the Alternative Portfolio cost] **and will not consider these costs in the unit energy cost analysis.** [16]

If sunk and termination costs are included in the UEC analysis:

- The Site C UEC, would increase.
- The UEC of the Illustrative Alternative Portfolio would increase

The quantum of the increases depends upon the assumptions made concerning recovery periods. The following tables provide a sensitivity analysis. Please also refer to our response to question 4 for a more complete discussion about recovery of sunk and termination costs.

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[13] F1-1 Submission, p. 61.
[14] EIA Levelized Cost and Levelized Avoided Cost of New Generation Resources in the Annual Energy Outlook 2017, p. 1, https://www.eia.gov/outlooks/aeo/pdf/electricity_generation.pdf
[15] Final Report, p. 154.
[16] The wording in the Final Report has been corrected above to clarify that Site C sunk costs are excluded from the unit energy cost comparison.

Table 3: Unit Energy Cost Sensitivity Analysis – Sunk and Termination Costs

Site C			Illustrative Alternative Portfolio[17]			
Sunk costs[18] added?	**Amortization period (years)**	**Unit Energy Cost (F18$/MWh)**	**Sunk costs added?**	**Termination costs[19] added?**	**Amortization period (years)**	**Unit Energy Cost (F18$/MWh)**
No	n/a	**$44**	No	No	n/a	**$31**
Yes	70	**$57**	Yes	No	70	**$48**
	70	**$57**			50	**$49**
	70	**$57**			30	**$50**
	70	**$57**			20	**$52**
No	n/a	**$44**	No	Yes	70	**$45**
		$44			50	**$46**
		$44			30	**$48**
		$44			20	**$49**
Yes	70	**$57**	Yes	Yes	70	**$63**
	70	**$57**			50	**$64**
	70	**$57**			30	**$67**
	70	**$57**			20	**$70**

Table 4: Total Rate Impact Sensitivity Analysis – Sunk Costs

Site C			Illustrative Alternative Portfolio[20]		
Sunk costs[21] added?	**Amortization period (years)**	**Total Rate Impact (F18$million)**	**Sunk costs added?[22]**	**Amortization period for sunk and termination costs (years)**	**Total Rate Impact (F18$million)**
No	n/a	**$2,852**	No	30	**$3,147**
Yes	70	**$4,086**	Yes	70	**$4,399**
	70	**$4,086**		50	**$4,530**
	70	**$4,086**		30	**$4,775**
	70	**$4,086**		20	**$4,969**

[17] All scenarios are for the low load forecast, Panel market price assumption, BC Hydro financing, Medium Wind and Geothermal costs.
[18] Sunk costs of $2,100 million (F2018$)
[19] Termination costs of $1,800 million (F2018$).
[20] All scenarios are for the Low load forecast, Panel market price assumption, BC Hydro financing, Medium Wind and Geothermal costs.
[21] Sunk costs of $2,100 million (F2018$)
[22] Note that termination costs were included in the Total Rate Impact for the Alternative portfolio.

Question 2: Financing costs

The Deputy Ministers ask:

> *In the event that government elects to terminate the Site C project, has the Commission assumed that BC Hydro would develop and finance the projects included in the alternative portfolio (wind, geothermal) rather than independent power producers (IPPs)?*

Response

The Commission did not assume that BC Hydro would develop and finance the projects included in the alternative portfolio. Specifically, the Final Report states that "[t]he Panel makes no determination on whether BC Hydro or IPPs should undertake the investments included in the Illustrative Alternative Portfolio."[23]

The Deputy Ministers also ask:

> *We observe that the Commission has in some cases used BC Hydro's lower cost of capital financing to calculate the cost of the alternative portfolio presented in the report, affecting the valuation of those projects. Could the Commission offer its view of the impact that a higher cost of capital would have on ratepayers if the alternative portfolio were developed by independent power producers rather than directly by BC Hydro?*

Response

The Final Report, to assist users in performing sensitivity analysis on the financing cost assumptions, described how users can perform an analysis of the effect of using IPP financing assumptions:

> The updated spreadsheet now allows for the application of different financing costs for wind and geothermal projects. If financing costs are assumed to be the same as BC Hydro's financing cost for Site C (100% debt financing at a cost of 3.43%), the user should select 'BCH rate' in the drop-down menu of the 'Financing Option' variable of the 'Input and Output' tab. If these projects are assumed to be undertaken by IPPs and financed at the IPP financing rate assumed by BC Hydro at 6.4%, the user should select 'IPP rate' instead. If a different rate than 6.4% is assumed, the user can change the value of 'IPP Financing Rate in %' directly.[24]

The Commission notes that selecting the IPP rate in the model results in a financing rate assumption of 6.4% in real terms, whereas BC Hydro's IPP financing rate assumption is 6.4% in nominal terms. In order to model the effect of use of BC Hydro's IPP financing rate, the rate in the model should therefore be set to 8.5 percent.

The table below provides the results of the Illustrative Alternative Portfolio model if changes are made to the Commission financing cost assumptions. Please note that the sensitivity analysis below only reflects the increase in financing costs of IPP financed projects, and does not reflect the corresponding decrease in ratepayer risk:

[23] Final Report, pp. 159–160.
[24] Final Report, Appendix C, p. 2.

Table 5: Sensitivity analysis regarding wind/geothermal financing cost assumption[25]

	Illustrative Alternative Portfolio PV Cost		
Load forecast scenario	**Commission Assumptions [26] (BC Hydro financing rate of 3.43%)**	**Alternative financing cost assumption (BC Hydro IPP financing rate of 8.5%)**	**Increase/(Decrease) in Alternative Portfolio PV cost**
• High load forecast	$5,121 million	$5,831 million	$710 million
• Med load forecast	$4,618 million	$5,130 million	$512 million
• Low load forecast	$3,147 million	$3,359 million	$212 million

The Deputy Ministers ask:

> *[By procuring new supply from competitive processes] BC Hydro avoids assuming such debt on its balance sheet and only recognizes the incremental costs of new energy purchases which would include the private sector's annual debt servicing costs and equity return within approved purchase contracts.*
>
> *It would be helpful to understand how the Commission assesses the impact on ratepayers of the additional debt associated with the assumptions underlying the alternative portfolio. We would particularly appreciate better understanding the Commission's approach to using BC Hydro's cost of capital for IPP projects and the approach used for the cost of capital faced by an IPP (i.e. what IPPs actually pay) and the resultant rate impacts. For example, on page 159-160, the Commission appears to conclude that IPP financing is the relevant assumption for the alternative portfolio ...*

Response

On page 160 of the Final Report, the Commission stated that "the same financing cost should be assumed for Site C and the Illustrative Alternative Portfolio." The Commission consistently used the BC Hydro financing rate in its comparison between Site C and the Illustrative Alternative Portfolio, for the reasons set out in the Final Report, which are repeated below for convenience. The Final Report goes on to provide an analysis of the effect of using the IPP financing rate for the alternative portfolio, as provided above.

The Commission concluded that an analysis comparing Site C to an alternative portfolio should be agnostic as to the ownership structure used. The rationale for this approach is discussed in the Final Report:

> The question posed in the OIC- whether there is an alternative portfolio that will deliver the benefits of Site C at an equivalent or lesser cost – will yield a different response depending on what assumptions are made regarding whether the alternative portfolio is developed by BC Hydro or by an IPP. …

[25] Results in this table are based on the revised Illustrative Alternative Portfolio spreadsheet published on Nov. 16 with the A-26 errata.
[26] Final Report, p. 70, footnote 600.

> By contracting for the supply of energy from an IPP, as opposed to developing an energy source directly, BC Hydro will transfer development, construction and operating risk to the IPP. In the Panel's view, the analysis should reflect this transfer of risk. CEABC suggests that the effect of this transfer of risk should be reflected in the discount rate that is applied to each project. BC Hydro submits that it isn't practical to conduct such an analysis on a project to project basis. …
>
> The Panel makes no determination on whether BC Hydro or IPPs should undertake the investments included in the Illustrative Alternative Portfolio. This Inquiry is not the place to address the question of BC Hydro versus IPP ownership and determine the optimal price/risk allocation in energy purchase agreements between BC Hydro and IPPs. Indeed, this review is agnostic with respect to ownership structure and instead focuses on the inherent cost and performance attributes of the generating assets, and how those assets will meet needs and address risk within the broader generation portfolio.
>
> In order to ensure that the outcome of this review is not biased for or against a particular ownership structure, the Panel therefore determines that an "apples to apples" comparison requires that the same financing costs be assumed for both Site C and the Illustrative Alternative Portfolio. However, to address the concerns raised by BC Hydro, the Panel provides additional scenarios with different financing assumptions. For these scenarios, BC Hydro financing will only be applied to DSM initiatives, and IPP financing costs for all other generation sources. …[27]

With regards to the reference to "additional debt" associated with the alternative portfolio, the Commission notes that BC Hydro will be financing the Site C project with debt. Therefore, given the similar cost of Site C and the alternative portfolio, the Commission sees no "additional debt" in the event that BC Hydro were to build alternative generating projects instead of Site C.

[27] Final Report, pp. 159, 160.

Question 3: Demand-side management

The Deputy Ministers ask:

> *Government will need to consider the total cost of potential demand side management initiatives (rather than just the utility's costs) as it considers the alternatives. Could the Commission advise how the inquiry Terms of Reference led to assessing demand-side measures based on the Utility Resource Cost standard, when Total Resource Cost has been the standard for prior Commission proceedings?*

Response

The Report stated:

> **With regard to what DSM cost should be included in the Alternative Portfolio, the Panel finds that the cost should be the utility cost as section 3(b)(iv) of the OIC [questions] refers to the cost to ratepayers.**[28]

The terms of reference for the Inquiry requested that the Commission evaluate the costs to ratepayers of continuing, suspending or terminating construction of Site C. The Commission interpreted the phrase "costs to ratepayers" as referring to costs that would recovered through BC Hydro's revenue requirement. The Report also stated: "When calculating cost to ratepayers, we calculate the NPV of the incremental revenue requirement of the item in question."[29]

The Commission did not include costs that would be incurred by other parties, such as the government or individuals; neither did the Commission consider broader societal costs or benefits in the financial analysis. Therefore, when considering the costs to ratepayers of the DSM programs, the Commission included only the costs incurred by BC Hydro.

The Deputy Ministers ask:

> *It is our understanding that in previous proceedings the Commission has concluded that the Total Resource Cost (TRC) test is the appropriate way to evaluate demand side management (DSM) in comparison to other resources. In this inquiry, the Commission's model uses the Utility Resource Cost (URC) standard. We believe that using the URC model may underestimate the actual cost of DSM to ratepayers. It would be helpful for us to understand the Commission's rationale in choosing a test methodology that differs from past practice. Could the Commission confirm that the TRC test remains the appropriate metric, and if so, what impact would this have on the analysis.*

Response

The total resource cost test remains an appropriate metric for analyzing whether or not to proceed with DSM programs. As we noted in the final report: "Regarding the use of the utility cost compared to the total resource

[28] Final Report, p. 38.
[29] Final Report, p. 164.

cost, the Panel agrees that BC Hydro should not be undertaking DSM programs that do not pass the total resource cost test."[30]

We also noted that the level of DSM investment included in the Illustrative Alternative Portfolio, a level originally recommended by BC Hydro in the 2013 IRP,[31] could reasonably be considered to pass this test: "However, the illustrative DSM portfolio only includes the first (lowest cost) block of BC Hydro's estimated incremental DSM opportunities. The Panel considers that the Illustrative Alternative Portfolio assumption that the programs in this first block all pass the total resource cost test is reasonable."[32]

The Commission did not use a utility resource cost standard in determining the appropriate level of DSM investment to include in the Illustrative Alternative Portfolio. Therefore, the Commission sees no impact to the analysis.

Once the level of DSM investment in the Illustrative Alternative Portfolio was determined, the Commission then addressed the question of its costs to ratepayers, as set out in the terms of reference. As explained in the answer to the question above, the Commission included only the costs that would be incurred by BC Hydro, and thus passed on to ratepayers. The rationale for this approach is addressed in the Final Report:

> With regard to what DSM cost should be included in the Alternative Portfolio, the Panel finds that the cost should be the utility cost as section 3 (b)(iv) of the OIC refers to the cost to ratepayers, as opposed to the BC cost or the societal cost.
>
> For example, the industrial load curtailment DSM program has a utility cost of $75/kW-year, while BC estimates that the total resource cost (i.e. the cost to the customer of curtailing) is $60/kW-year. The Panel considers it would not be consistent with the treatment of Site C to include in the Alternative Portfolio the cost to the industrial customer of curtailing supply (total resource cost), instead of the cost to the utility of obtaining the curtailment (utility cost).[33]

The Deputy Ministers also ask:

> *The report identifies an aggressive DSM program, coupled with load curtailments as a way to achieve the alternative portfolio scenario. We would appreciate further information from the Commission on how such load curtailments would practically be achieved in the natural resource sector without impairing operations, jobs and economic growth for sectors already facing trade sanctions and pressures*

Response

The Commission would not characterize the DSM plan included in the Illustrative Alternative Portfolio as aggressive. The level of DSM included in the Illustrative Alternative Portfolio is, in fact, the level recommended by BC Hydro in its 2013 Integrated Resource Plan, and was the least aggressive apart from one of the five levels of DSM spending that BC Hydro modelled at that time.[34]

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[30] Final Report, appendix A, p. 38.
[31] Final Report, Appendix A, p. 34.
[32] Final Report, appendix A, p. 38.
[33] Final Report, Appendix A, pp. 38, 39.
[34] Final Report, Appendix A, p. 34.

The Commission believes that load curtailment can be a mechanism to retain and attract additional industrial load, and so enhance, rather than impair, operations, jobs and economic growth. The Final Report identifies a desire by industry for higher levels of industrial curtailment opportunities than included in the Illustrative Alternative Portfolio. Specifically, the Association of Major Power Customers (AMPC) has argued for BC Hydro to offer higher levels of load curtailment as being in the interests of its members:

> Curtailable loads have already demonstrated that they can feasibly, cost-effectively and dependably provide system capacity for the necessary duration of peak load events. AMPC's October 11 submission details the specifics of AMPC's position. Once long term curtailable tariffs are established; scalable capacity resources can be delivered in appropriate quantities and at very short notice compared to generation sources. From BC Hydro's forecasts of capacity and energy need, the immediate implementation of curtailable contracts and/or tariffs could provide the necessary time to take a more detailed look at how future energy needs are most reliably and affordably provided. This time is particularly valuable during a period of significant technological development in energy storage, to reduce the risk of adopting a potentially short-lived technology path. Moreover, this provides a non-rate mechanism to retain existing, and attract additional, industrial load.
>
> …the Commission should, as part of any alternative energy portfolio evaluated, consider the full use of industrial load curtailment to generate needed system capacity, because load curtailment is a well-developed, well-studied program that can be implemented economically and quickly, without the need to speculate on the its potential availability in the future.[35]

[35] Final Report, Appendix A, pp. 72, 74, 75. Emphasis added.

Question 4: Amortization of sunk/termination costs

The Deputy Ministers ask:

> *If the Site C project were terminated, the $4 billion sunk and remediation costs would need to be recovered, and the amortization period of that recovery would affect BC Hydro rates. Could the Commission please clarify whether it assumed that that these costs would be recovered over 10, 30 or 70 years?*

Response

The Commission made no assumptions on the recovery of sunk and termination costs. The Final Report states:

> Regarding the potential mechanisms to recover termination costs, the options available are either from BC Hydro ratepayers, the shareholder or some combination of the two. If these costs are to be recovered from ratepayers a further issue is over what period they should be recovered.
>
> Generally speaking, a regulated utility is entitled to recover from its ratepayers, all prudently incurred expenditures. Therefore, the issue would be whether the costs to terminate the project were prudently incurred and this can only be determined after the expenditures have been made.
>
> In regard to the recovery period, this requires further analysis. Considerations include intergenerational equity – too long a period risks forcing customers who may not benefit from the expenditure to pay for it. If the payback period is too short, there is a risk of rate shock. This Panel takes no position at this time what the recovery period should be and notes that it would be subject to Commission approval.
>
> The same principles apply to the recovery of the sunk costs. There are some that suggest that if the project is terminated, this could be an indicator that the decision to go ahead with the project was not prudent. Others argue that since the project was not approved by the Commission, the costs were, by definition, not prudently incurred.
>
> **The Panel takes no position on the recoverability from ratepayers for sunk and termination costs. Further, we take no position on the recovery period for sunk and termination costs.** However, for the analysis of ratepayer impacts of the termination scenario, we have assumed that termination costs will be recovered from ratepayers over a 10, 30 and 70 year recovery period.
>
> Although we do not consider the rate impact of sunk costs when comparing the continue and termination scenario, the costs must be recovered. In the case of Site C being completed these costs would be included in the project costs, and barring any disallowance, would be recovered from ratepayers over the 70-year amortization period proposed. In a terminate scenario, again assuming the costs are to be recovered from ratepayers, to determine the cost impact to ratepayers requires assumptions regarding the amortization period.

The Deputy Ministers also ask:

> *Fair and appropriate rate-setting principles for rate-regulated utilities typically aim to avoid causing future generations to pay for investments from which they will derive no benefit. From the Commission's perspective, can recovery of the sunk and remediation costs of Site C over longer periods of 30 to 70 years remain consistent with these inter-generational principles?*

Response

The Commission reiterates that we take no position on the recovery period for sunk and termination costs. The recovery period would be the subject of Commission review if, and when these costs are incurred.

When considering the recoverability of any costs, there are a number of regulatory principles considered, including:

- Price signals that encourage efficient use and discourage inefficient use (economic efficiency);
- Fair apportionment of costs among customers (fairness);
- Avoid undue discrimination (fairness);
- Customer understanding and acceptance, practical and cost effective to implement (practicality);
- Freedom of controversies as to proper interpretation (practicality);
- Recovery of the revenue requirement (stability);
- Revenue stability (stability); and
- Rate stability (stability).[36]

The above considerations would apply to the recovery period of both termination costs and sunk costs.

We generally agree with the Deputy Ministers' statement "Fair and appropriate rate-setting principles for rate-regulated utilities typically aim to avoid causing future generations to pay for investments from which they will derive no benefit." Intergenerational equity is an important consideration when considering the deferral of cost recovery. However, in the termination case, both the sunk and termination costs relate to a stranded asset, and it is important to note that no-one benefits from a stranded asset. Therefore there is no more – or less – justification that any particular generation should be more liable than another for the costs related to that stranded asset.

The Deputy Ministers also ask:

> *Recently it has been stated that recovering the project's sunk and remediation costs over a I0-year period would lead to a 10 per cent hike in BC Hydro rates. Is this assertion consistent with the Commission's thinking?*

Response

The table below shows the initial effect on the revenue requirement of amortization of Site C sunk costs, followed by the combined effect when estimated termination costs have been incurred. BC Hydro's F2018 revenue requirement request of $4,626 million has been used to estimate the year one rate impact effect of the

[36] Bonbright principles, BC Hydro 2015 Rate Design Application, Decision dated January 20, 2017, pp. 11, 12

alternative amortization options.[37] BC Hydro real rate increases subsequent to F2018 will result in a lower percentage impact than that indicated on the table below.

Table 6: Rate impact of alternative amortization period for Site C sunk and termination costs

Amortization Period (years)	Year one costs recovered	Revenue requirement impact
Site C sunk costs only ($2.1 billion)		
10	302	6.5%
30	152	3.3%
50	122	2.6%
70	109	2.4%
Total Site C sunk costs and termination costs ($3.9 billion)		
10	560	12.1%
30	282	6.1%
50	226	4.9%
70	203	4.4%

The Panel therefore confirms that the use of a 10-year amortization period for Site C sunk and termination costs have a potential rate impact of 10 percent. However, the actual rate impact of Site C termination will reflect the amortization period selected, which will in turn be driven by intergeneration equity and rate shock concerns, and the degree to which sunk or termination costs prove to have been prudently incurred. The Panel notes that the year one revenue requirement impact of Site C (before export revenues) is estimated at $499 million (F2025).[38]

The scenarios for the total rate impact of the Illustrative Alternative Portfolio as presented in the Final Report[39] include termination costs of $1,800 million. The analysis in the tables above suggests a situation whereby the sunk and termination costs of Site C would be recovered separately from the costs of the Illustrative Alternative Portfolio. To avoid double counting, it is therefore appropriate to present accompanying analysis that demonstrates the impact of removing termination costs from the total rate impact of the Alternative Portfolio. Table 7 below indicates that the illustrative Portfolio would be less costly in all load forecast scenarios with termination costs excluded from the rate impact.

[37] BC Hydro F2017-F2019 Revenue Requirement Application, Exhibit B-1-1, p. 1-38
[38] BC Hydro Site C cost calculator (Submission F1-4, BC Hydro, IR 2, Attachment 3), as adjusted to show total Site C costs (including sunk costs) as $10 billion.
[39] Final Report Executive Summary Errata, Corrected Table 43, p.10

Table 7: Total Rate Impact – Termination Costs Excluded from Alternative Portfolio

	Site C– Total Rate Impact (F18$milllions)	Illustrative Alternative Portfolio – Total Rate Impact		Difference between Site C and Alternative Portfolio – Termination costs excluded (F18$milllions)
		Termination costs included (F18$milllions)	Termination costs excluded (F18$milllions)	
Low Load Forecast	2,852	3,147	1,752	($1,100)
Medium Load Forecast	3,901	4,618	3,222	($679)
High Load Forecast	4,325	5,121	3,726	($599)

In addition, the Appendix to the Deputy Ministers' letter asks:

> *It would be helpful if the Commission could clarify how the choices of cost amortization and recovery periods in the Termination scenario fit within appropriate utility rate-setting principles that recognize and avoid unnecessarily transferring current utility costs to future user generations when there are clearly no longer directly-related assets or benefits being provided. Such decisions lead rate-regulated accounting practice and use of regulatory accounts, which are areas of particular interest by the provincial Auditor General as well as credit rating agencies.*

Response

The issue of the appropriate period to recover Site C sunk and remediation costs is addressed in the Site C Final Report:

> In regard to the recovery period, this requires further analysis. Considerations include intergenerational equity – too long a period risks forcing customers who may not benefit from the expenditure to pay for it. If the payback period is too short, there is a risk of rate shock. This Panel takes no position at this time what the recovery period should be and notes that it would be subject to Commission approval. …
>
> **Further, we take no position on the recovery period for sunk and termination costs.** However, for the analysis of ratepayer impacts of the termination scenario, we have assumed that termination costs will be recovered from ratepayers over a 10, 30 and 70 year recovery period.
>
> Although we do not consider the rate impact of sunk costs when comparing the continue and termination scenario, the costs must be recovered. In the case of Site C being completed these costs would be included in the project costs, and barring any disallowance, would be recovered from ratepayers over the 70-year amortization period proposed. In a terminate scenario, again assuming the costs are to be recovered from ratepayers, to determine the cost impact to ratepayers requires assumptions regarding the amortization period.[40]

As noted above, the Commission considers numerous factors in determining the appropriate amortization period to use to recover Site C sunk costs and termination costs.

[40] Final Report, pp. 163–164.

Question 5: Load forecast

The Deputy Ministers ask:

> *We are unaware of prior instances when anything other than BC Hydro's mid-load forecast has been used for planning purposes. For that reason, we would like to clarify:*
>
> > *Did the Commission assume lower demand for electricity (reflected in the low-load forecast used in the report) because it is forecasting a period of lower economic growth for the province in which major power consumers such as mining, forestry, technology and commercial sectors are in decline?*

Response

The Commission did not assume a lower demand for electricity "because it is forecasting a period of lower economic growth for the province." Further, the Report does not state, nor does it suggest, that "major power consumers such as mining, forestry, technology and commercial sectors" are in or are going into "decline". On the contrary, the Report specifically acknowledges that there have been some positive developments in the non-LNG large industrial load, but goes on to conclude that these positive developments are not sufficient to offset the negative developments in the potential BC LNG sector.

The Commission's consideration of the load forecast was based on a holistic assessment of the factors that drive demand for electricity. In our answer to the Deputy Ministers' question below regarding the rationale for the Commission's position, we present a description of the seven factors we considered. These include three factors that are directly related to economic growth: recent developments in the industrial sectors, GDP and other forecast drivers, and flattening electricity demand.

The Deputy Ministers also ask:

> *Does the Commission include in its load forecast the potential increased electrical power demand of meeting the province's stated objectives to reduce greenhouse gas emissions through greater electrification of our economy?*

Response

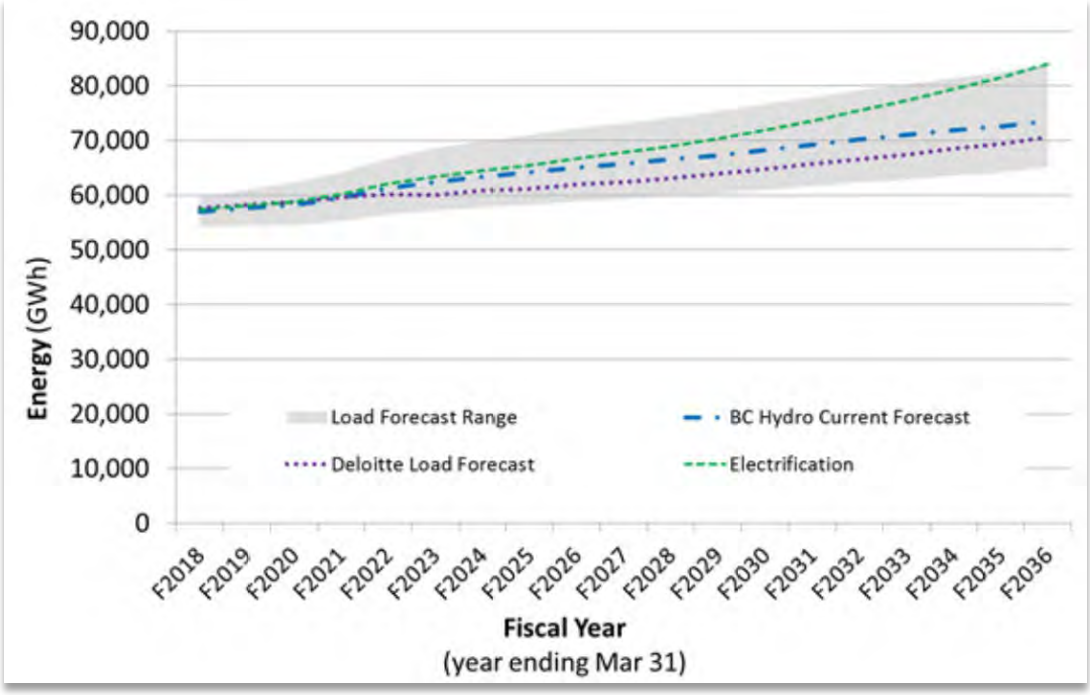
The Commission does not have a load forecast. The terms of reference required us to use BC Hydro's load forecast from the 2016 Revenue Requirements Application, which has a mid-level projection within a high and a low band. We were also required to seek BC Hydro's view on factors which might influence expected demand toward the high or low cases.

The Commission did consider electrification in the Final Report both from the perspective of impacts on the load forecast over the 20-year period and disrupting trends over time. These are considered below.

In its submissions, BC Hydro highlights the emerging potential for load growth from initiatives targeting greenhouse gas emission reductions through electrification of fossil-fuel powered end uses. BC Hydro states "electrification of energy loads currently served by fossil fuels such as space and water heating, vehicles and industrial equipment could reasonably cause demand for electricity to exceed BC Hydro's mid forecast in the Current Load Forecast."

However, BC Hydro does not account for electrification initiatives directed at reducing greenhouse gas emissions in its Current Load Forecast because the timing and magnitude of the potential increase is uncertain at this early stage. BC Hydro presents the potential for electrification to have an upward impact on the load forecast in the figure below.

Figure 1: BC Hydro's Load Forecast Range, Impact of Electrification, and Deloitte's "Alternative" Load Scenario



Although available information indicates that the effects of electrification on BC Hydro's load forecast could potentially be significant, the timing and extent of those increases remain highly uncertain. Given the uncertainty, the Site C Inquiry Panel agreed with BC Hydro that additional load requirements from potential electrification initiatives should not be included in the load forecast for the purpose of resource planning.

The extent and timing of electrification initiatives will be a matter of government policy. In the absence of such policy, it is not appropriate to include any potential additional load requirements from electrification initiatives in the load forecast for resource planning. Should the government set further policy with respect to electrification, BC Hydro would need to prepare an updated load forecast reflecting the impact of such policies.

Although not taken into account in the load forecast, electrification is still an issue for consideration. In its report, the Panel noted that if electrification does materialize in the future, it is possible that some of the higher electricity demand could be offset with aggressive conservation measures, including DSM programs that achieve load reductions similar in magnitude to those experienced in New England.[41]

[41] Page 75 of the Final Report includes the following submission by CanWEA: "These [downside risks] are very real risks that are being realized in many other North American electricity markets. In New England, where I am from, the most recent long-term electricity demand forecast by the Independent System Operator is for a .6% compound annual decline in energy

The Panel also acknowledged numerous submissions identifying disruptive factors that could potentially decrease demand, including the potential impact of expanded distributed generation. However, because these downward impacts on load are uncertain, the Panel did not identify any specific trends that would suggest an adjustment to the Current Load Forecast is required.

The Deputy Ministers further ask:

> *We have noted that the Commission has concluded that BC Hydro's low load forecast was most appropriate for an assessment of the need for the capacity of Site C. It would be helpful for us to further understand the rationale, and whether the assessment includes the load requirements needed to meet the Province's Clean Energy Act energy objectives of:*
>
> - *Reducing greenhouse gas emissions by 2050 by 80% less than 2007 levels;*
> - *Encouraging the switching from one kind of energy source or use to another that decreases greenhouse gas emissions in British Columbia; and,*
> - *Encouraging communities to reduce greenhouse gas emissions and use energy efficiently.*

Response

To recap the Final Report, the Commission concluded:

> **Overall, the Panel finds BC Hydro's mid load forecast to be excessively optimistic and considers it more appropriate to use the low load forecast in making our applicable determinations as required by the OIC. In addition, the Panel is of the view that there are risks that could result in demand being less than the low case.**[42]

In making findings on BC Hydro's load forecast, the Commission considered the following factors:

1. Recent developments in the industrial sectors
2. Accuracy of Historical Load forecasts
3. GDP and other forecast drivers
4. Price Elasticity assumptions
5. Future Rate increases
6. Potential disrupting trends
7. Flattening electricity demand

Each of the seven items considered by the Commission in arriving at its determination on BC Hydro's load forecast are addressed in detail in the Final Report and are summarized below.

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consumption over the next ten years, with no meaningful increase in peak load. New York ISO is also forecasting a decline in energy consumption (-.2% per year)."

[42] Final Report, p. 77.

Recent developments in the industrial sectors

The Panel reviewed recent developments in the industrial sector and concluded:

> **The Panel finds the developments since the Current Load Forecast was prepared, as reported by BC Hydro, can reasonably be expected to reduce demand from the expected case or mid forecast.**
>
> The Panel acknowledges there have been some positive developments in the non-LNG large industrial load that BC Hydro suggests provide a net increase in demand since the Current Load Forecast was prepared (an anticipated positive total variance is approximately 750 GWh/100 MW in the short and medium term and 965 GWh/114 MW over the long-term). However, given the risk and volatility of the industrial load and its susceptibility to cyclical ups and downs, and the risks to the large industrial load set out by AMPC, the Panel is unable to draw any conclusions that these recent developments will result in a permanently positive impact on industrial demand. In any event, in the Panel's view these positive developments in the non-LNG sector are not enough to offset negative developments for a potential BC LNG sector.
>
> **The Panel finds that developments since the Current Load Forecast was prepared have significantly reduced the probability that the majority of BC Hydro's forecast LNG load will materialize.** Regarding the potential LNG industrial load, BC Hydro itself states there are questions as to whether BC has missed the window of opportunity for LNG. While BC Hydro points to certain third-party market views that still show some support for the opportunity to develop LNG in BC, the Panel notes the significant uncertainty expressed in most market views, the recent cancellation and postponement of several large potential BC LNG projects, and the higher costs of potential BC LNG projects compared to existing and potential projects in other jurisdictions. The Panel also agrees with several parties who express concern with the fact that BC Hydro had not made a probabilistic assessment of the likelihood of the LNG load materializing. The Panel agrees with Finn that the three projects cited by BC Hydro face uphill battles, especially given the current poor market conditions. [43]

Accuracy of historical load forecasts

After reviewing the accuracy of BC Hydro's historical load forecasts, the Panel stated:

> As noted in its Preliminary Report, **the Panel finds that the historical instances of over-forecasts are greater than under-forecasts, especially in the industrial load, and that the accuracy of BC Hydro's historical industrial forecasts looking out three and six years has been considerably below industry benchmarks.**
>
> The Panel acknowledges BC Hydro's argument that the drivers of historical industrial forecast variances are not relevant to the expected accuracy of the Current Load Forecast, especially considering the impacts of large discrete customer load attrition between 2006 and 2010 and the steps BC Hydro describes it has taken to ensure its existing industrial forecasts are reasonable. However, as pointed out by CEC, some of these declines in industrial load could or should have been anticipated and may represent a bias towards over-forecasting. Accordingly, while the Panel does not place significant weight on the historical inaccuracies in the load

[43] Final Report, p. 78.

> forecast, it does approach the Current Load Forecast with some skepticism, especially as it relates to the industrial load forecast.[44]

GDP and other forecast drivers

After reviewing BC Hydro's GDP growth assumptions, the Panel stated:

> …The Conference Board of Canada forecast projects the real GDP will grow by 2.6 percent on average between 2016 and 2020 and then drop to an average of 2.3 percent between 2021 and 2025. In contrast, BC Hydro's projection results in an average growth rate of 3.5 percent over the same five years. BC Hydro's forecast results in the BC economy being six percent larger than the CBoC's forecast by 2025. The Panel considers BC Hydro's average growth rate of 3.5 percent to be excessive.
>
> …
>
> The Panel remains concerned that BC Hydro's GDP and disposable income forecast drivers are higher than other comparable third party estimates, such as the CBoC. Based on the evidence presented in this Inquiry, the Panel can make no definitive finding on the appropriate GDP or disposable income driver to apply. However, considering the historical over-estimates in the load forecast as noted above, the Panel approaches BC Hydro's estimates with skepticism given that these key drivers are both considerably higher than other third party estimates and use of the lower estimates would result in a lower load forecast. **Accordingly, the Panel finds BC Hydro's mid load forecast is higher than if it used the CBoC estimates and adjusting for this could reasonably be expected to influence demand towards the low load case.** [45]

Price elasticity assumptions

With regard to price elasticity, the Panel made the following findings:

> **The Panel finds the -0.05 long-run price elasticity used by BC Hydro for all rate classes to be too low in magnitude to reflect the degree of change in demand for a given change in price. Accordingly, the Panel finds BC Hydro's mid load forecast is higher than would otherwise be the case if it used lower price elasticity factors, and that adjusting for this would reduce demand towards BC Hydro's low load forecast case.**
>
> **The Panel finds that BC Hydro should be using a long-run price elasticity given the long 70 year time horizon of Site C. The Panel also finds that the international literature shows that long-run elasticities are higher than short-run elasticity. It is not clear to the Panel that BC Hydro's empirical studies have appropriately estimated long-run price elasticities since the residential inclining block rate and the transmission stepped rates have not been in place over a long time horizon.**
>
> **…**
>
> **The Panel finds the residential long-run price elasticity is likely to be more than -0.05.** BC Hydro's empirical evidence shows a range from 0 to -0.13; however, the zero in the low-end of the range with no price response indicates the study results may not be reliable. The Panel

[44] Final Report, P. 78.
[45] Final Report, pp. 78–79.

> notes the study by Paul, Myers and Palmer shows the low-end of the range to be at -0.14 for residential long-run elasticity.
>
> BC Hydro's empirical evidence shows that the price elasticity for commercial and industrial general service customers is close to zero so BC Hydro adopted -0.05. **The Panel finds that BC Hydro's empirical evidence for the price elasticity of commercial customers is unreliable in determining the long-run price elasticity.** The Panel notes the international literature shows varied results for commercial customers. Paul, Myers, and Palmer had a long-run elasticity average of -0.29 with a range of -0.02 to -0.70. Bernstein and Griffin had a single estimate of -0.97 which suggests the elasticity could be higher than -0.05.[46]

In addition, the Panel noted BC Hydro's consultant GDS's recommendation that BC Hydro's price elasticity coefficients used to estimate "rate impacts," which were developed in 2007, need to be updated.

Future rate increases

BC Hydro assumed no real rate increases beyond the end of the 10 Year Rates Plan (F2024).[47] The Commission concluded with regard to this assumption:

> **The Panel finds BC Hydro's demand forecast is sensitive to rate changes even using BC Hydro's low price elasticity factors. Accordingly, any real increase in rates beyond the rates reflected in the 2013 10 Year Rates Plan and any subsequent real rate increase could reasonably be expected to influence demand towards the low load case.**
>
> **The Panel finds there will be considerable upward pressure on rates for the remainder of the 2013 10 Year Rates Plan and beyond fiscal 2024. The Panel finds the risk associated with this upward pressure on rates is especially concerning given the submissions related to potential "demand destruction" that could result from the impact of real rate increases on already vulnerable industrial customers and the likelihood that even nominal rate increases will increase energy poverty among BC's low income households.**[48]

Potential disrupting trends

The Panel raised as a concern that, given the long life of the Site C asset, BC Hydro has only identified a potential upside risk to the load forecast from electrification, and had not identified any potential downside risk. The Panel concluded:

> **Given the uncertainty, the Panel finds additional load requirements from potential electrification initiatives should not be included in BC Hydro's load forecast for the purpose of resource planning.** Although available information indicates that the effects of electrification on BC Hydro's load forecast could potentially be significant, the timing and extent of those increases remain highly uncertain.
>
> BC Hydro has not included in its Current Load Forecast additional load requirements from electrification initiatives to reduce greenhouse gas emissions. The Panel agrees with BC Hydro and Hendriks *et al.* that the timing and magnitude of the increase is uncertain at this time. However, electrification is still an issue for consideration. The Panel notes that if electrification

[46] Final Report, pp. 79–80.
[47] Final Report, p. 65.
[48] Final Report, p. 80.

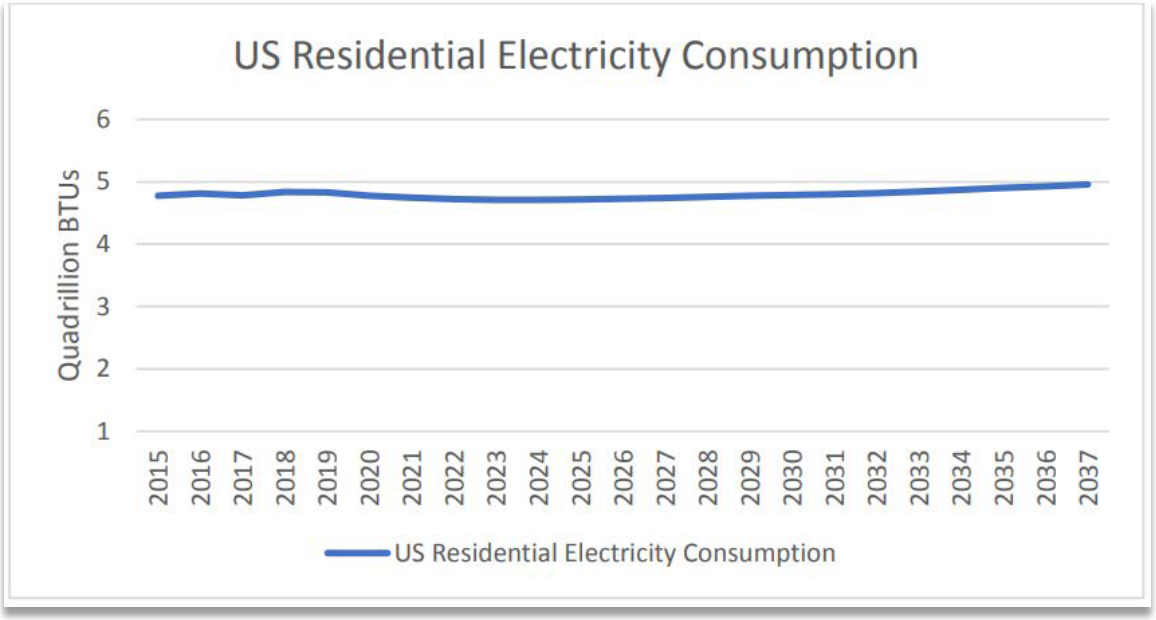
does materialize in the future, it is possible that some of the higher electricity demand could be offset with aggressive conservation measures, including DSM programs that achieve load reductions similar in magnitude to those experienced in the New England states.

The Panel acknowledges the numerous submissions identifying disruptive factors that could potentially decrease demand, including the potential impact of expanded distributed generation. However, because these downward impacts on load are uncertain, the Panel did not identify any specific trends that would suggest an adjustment to the Current Load Forecast is required.[49]

Flattening electricity demand

CEC, Surplus Energy Match and CanWEA all provide evidence that total demand is not growing in most jurisdictions in North America – in most cases it is flat or declining. In British Columbia the declining use per customer over the last 10 years has largely offset the effects of population growth.[50]

Figure 2: US Residential Electricity Consumption



The Deputy Ministers ask:

It has been government's assumption that electrification with low carbon electricity would be a key initiative to achieve greenhouse gas reductions. The provincial government is working with the Government of Canada on electricity system infrastructure investments to reduce and avoid greenhouse gas emissions, and has enabled BC Hydro to pursue electrification initiatives under the Greenhouse Gas Reduction (Clean Energy) Regulation under the Clean Energy Act. It would be helpful for our ministries to understand if the Commission has a different outlook, and if the

[49] Final Report, pp. 81–82.
[50] Final Report, p. 82.

Commission could further describe the impact on its analysis of electrification initiatives to meet greenhouse gas reduction objectives.

Response

The Commission's outlook on electrification and its effects on the load forecast are provided in the Final Report. We refer the Deputy Ministers to our previous answer for a summary of the material.

The Deputy Ministers also ask:

We understand that BC Hydro has provided the Commission with a description of its view of what BC's economic environment would look like under a low load outlook scenario. It would [be] helpful if the Commission could further describe its interpretation of the low load outlook. We observe that the Commission's view is that the outlook could be even lower than that presented in BC Hydro's low-load scenario, and we are interested in understanding how that outlook is based on realistic economic sustainability around which the alternative portfolio would be premised.

Response

The Commission's consideration of the load forecast was based on a holistic assessment of the factors that drive demand for electricity. In our answer to the question above regarding the rationale for the Commission's position, we have included a description of the seven factors we considered. These include three factors that are directly related to economic growth: recent developments in the industrial sectors, GDP and other forecast drivers, and flattening electricity demand.

Additional question: Dispatchability

The Deputy Ministers ask:

> *It would also be useful to know if the Commission examined the value of "dispatchable" resources versus intermittent resources, particularly as applied to the goal of moving industrial energy requirements now and in future to low carbon electricity.*

Response

The Commission examined the value of "dispatchable" versus intermittent resources in its selection of generation options in the Illustrative Alternative Portfolio, and concluded that "increasingly viable alternative energy sources such as wind, geothermal and industrial curtailment could provide similar benefits to ratepayers as the Site C project with an equal or lower Unit Energy Cost."[51]

Appendix A of the Final Report contains the Commission's analysis of each generation option in the Illustrative Alternative Portfolio, and the degree to which they provide "dispatchable" energy. With regards to wind energy, for example, the largest single contributor to the Illustrative Alternative Portfolio, the Commission stated:

> BC Hydro states that Site C (capacity 1,145 MW) can integrate 900 MW of wind. However, the Panel notes that BC Hydro's existing modest level of wind penetration (780 MW) and high levels of hydro generation providing reserves (GM Shrum, Mica and Revelstoke with a combined capacity around 8,000 MW) means that BC Hydro would not be expected to need Site C to integrate these additional wind farms.[52]

In comparison, the Illustrative Alternative Portfolio includes 444 MW of wind generation in the low load forecast and 729 MW in the high load forecast.[53]

[51] Executive Summary, p. 3.
[52] Final Report, Appendix A, p. 32.
[53] Final Report, Errata, p. 6.