CENTRE HELIOS

RESEARCH AND EXPERTISE IN ENERGY

NO. S-160488
VANCOUVER REGISTRY

COMMENTS OF PHILIP RAPHALS IN RESPONSE TO AFFIDAVIT #2 BY MICHAEL SAVIDANT

February 21, 2016

1. I am the Executive Director of the Helios Centre, a research group that provides independent expertise on energy issues and, as such, I have personal knowledge of the facts and matters hereinafter deposed to, save and except for information imparted to me by other people, in which case I believe the source of the information to be reliable and I believe the information to be true.

2. I provided an Affidavit #1 in the present proceeding, dated February 11, 2016.

3. In his Affidavit #2 (the "Affidavit"), Michael Savidant responds to certain statements made in my Affidavit #1 and in the report attached as Exhibit B thereto (the "Report"). In this document, I reply to Mr. Savidant's Affidavit.

4. At paragraph 24 of his Affidavit, Mr. Savidant refers to KPMG's letter report entitled "Site C Clean Energy Project – Model Review, reviewing BC Hydro's financial model" (Exhibit C). He states that KPMG concluded that "The Financial Model also appears to have been constructed appropriately, insofar as its logic and arithmetic integrity is concerned." However, Mr. Savidant neglects to mention the numerous caveats in that letter, stated as follows on the first two pages:

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Our work did not include any of the following:

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

The procedure we used to perform the work set out above will not constitute an audit or review made in accordance with any generally accepted auditing standards, or company law, or assessment of the technical feasibility or technical engineering review, or compliance with application legislation.

5. Logic and arithmetic integrity are not the only relevant and necessary criteria for relying on the results of a financial model. In particular, it is essential to assess commercial risks before concluding that the financial projections contained in the model are likely to be achieved (caveat #1), to review implicit assumptions (caveat #3), to assess the completeness of the assumptions and inputs used (caveat #5), and to test the model's sensitivity analyses (caveat #6).

6. Any weight given to the KPMG report should take these factors into account.

7. In paragraphs 70 and 71, Mr. Savidant takes issue with my statement "that some construction costs are likely in US dollars and that the devaluation of the Canadian dollars (sic) likely increases the overall capital cost." He claims at paragraph 71 that BC Hydro and its contractors mitigate currency risk through changing source locations. However, insofar as the cause is the devaluation of the Canadian dollar, changing sourcing may not relieve the difficulty, though it is true that falling commodity prices may tend to counterbalance this effect. That said, the fact remains that Mr. Savidant has chosen not to present an updated capital cost for Site C, nor has he offered any explanation for choosing not to do so.

8. At paragraph 90, Mr. Savidant makes reference to the issues of "need for the Project" and "the timing of the need," which were addressed in BC Hydro's Environmental Impact Statement. He produces excerpts of the Joint Review Panel Report as Exhibit J.

9. In several key passages, the Joint Review Panel's conclusions in fact undermine Mr. Savidant's thesis and support my analysis of it. For instance, its section on Exports (s. 15.4.3.2) concludes that "relying on exports to absorb surplus production would likely be very expensive." The section on exports in the Joint Review Panel's Report is reproduced here, in its entirety:

> **15.4.3.2 Exports**
>
> A further consideration with respect to supply cost is the ability of selected alternatives to follow demand. In the past, it has been relatively easy for BC Hydro to sell its surpluses at prices that fully covered its costs. Even so, there were regulatory risks, such as the decision by the U.S. Federal Energy Regulatory Commission in 2013 to fine BC Hydro (i.e. B.C. ratepayers) three quarters of a billion dollars for alleged infractions of U.S. rules during the Enron crisis of 2001.
>
> Despite some short-term difficulties currently plaguing supply in California, BC Hydro's outlook is that the market prices it would achieve through the forecast period would average only $35/MWh, radically less than the marginal cost of production and delivery (about $94/MWh).
>
> Site C would be a large, sudden addition to supply. BC Hydro projects losing $800 million in the first 4 years of operation. These losses would come home to B.C. ratepayers in one way or another. (BC Hydro's view is that they will be more than made up in lower future rates.) They could be minimized through smaller supply additions that more closely follow the load, or avoided altogether by a minor modification of the self-sufficiency objective. It would make financial sense to import cheap power until its cost rises to the cheapest of domestic alternatives, or until the domestic market can absorb most of the new supply.
>
> **The Panel concludes that relying on exports to absorb surplus production would likely be very expensive.**

10. Furthermore, in section 15.6 (page 306), the Panel stated:

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

11. The Panel also expressed significant reservations with respect to BC Hydro's estimation of the capital cost of Site C (page 280):

> Because BC Hydro has not built a project of this size for many years, the Panel feels that there is little corporate experience to draw on. When asked for its recent experience with smaller capital projects, BC Hydro noted that its average cost overrun on recent projects of more than $50 million was 3.3 percent, and for generation projects, was -0.3 percent. The Panel is encouraged by these results.
>
> **The Panel cannot conclude on the likely accuracy of Project cost estimates because it does not have the information, time, or resources. This affects all further calculations of unit costs, revenue requirements, and rates.**
>
> **RECOMMENDATION 46**
> If it is decided that the Project should proceed, a first step should be the referral of Project costs and hence unit energy costs and revenue requirements to the BC Utilities Commission for detailed examination.

12. At paragraph 98, Mr. Savidant states that he “accepts that the general methodology of preparing a net present value of future costs and revenues used by Raphals and McCullough is conceptually reasonable.” The methodology used in my report takes into account both the additional costs and benefits related to delay and the export revenues during the years that would be affected by delay – revenues that are far below the Project costs for the same years. It is important to note that Mr. Savidant’s methodology fails to take this factor into consideration in any way. This failure is difficult to explain, given the commercial experience Mr. Savidant highlights in paragraph 2 of his affidavit, and his statements in paragraph 132 regarding his independence and objectivity.

13. In the section “Reliance on Market purchases,” starting at paragraph 102, Mr. Savidant claims that i) my approach, which relies on market purchases to meet energy and capacity shortfalls prior to the commissioning of Site C is inconsistent with the self-sufficiency requirement of the *Clean Energy Act* (paragraph 103) and ii) that creates unacceptable risks with respect to reliability (paragraphs 105 through 108). Finally, Mr. Savidant asserts that, iii) if the degree of market reliance in my report were to be found unacceptable, “it would be necessary to build new resources to fill demand requirements for the period of delay”.

14. Each of these statements is incorrect. I will address them in turn.

The Self-Sufficiency Requirement of the Clean Energy Act

15. In paragraph 103, Mr. Savidant summarizes the self-sufficiency requirement (“SSR”), as found in sections 2 and 6 of the *Clean Energy Act* and in B.C. Reg. 315/2010, enacted under that Act.

16. The assumptions I have made regarding market reliance are consistent both with these instruments and with BC Hydro’s practice in its Integrated Resource Plan. I will first demonstrate the consistency with the approach taken in the IRP, and then explain why that is consistent with the SSR.

Coherence with BC Hydro’s planning practices

17. Appendix 9A to the Final IRP of 2013, presented as Attachment 3 to my Affidavit #1, presents the details of the Base Resource Plans (BRP) and the Contingency Resource Plans (CRP) recommended in the IRP. The precise relationship between the Recommended Actions, including Recommended Action 6 cited in paragraph 87 of Mr. Savidant’s affidavit, is described in the introductory pages to Chapter 9 – Recommended Actions, of which a brief excerpt was attached to Mr. Savidant’s affidavit as Exhibit H. The entire chapter is attached to these comments as Exhibit A.

18. In particular, on page 9-5, it is indicated that “Table 9-2 is a summary of how the Recommended Actions are developed to align to the BRP, the BRP for Expected LNG Load, and the two CRPs.” The BRPs and CRPs thus reflect the detailed scenarios underlying the Recommended Actions.

19. If we turn to the Appendix 9A, which presents the detailed plans (Base and Contingency Resource Plans, with and without Expected LNG), the methodology used to construct them is presented in section 2, starting on page 1:

> ## 2 BRP and CRP Construction
>
> The BRPs and CRPs are constructed using the following general methodology:
>
> • BRPs:
>
> - start with the energy and capacity surplus/deficits in Chapter 4 (Table 4-18 and Table 4-19)
> - schedule Site C for in-service in F2024
> - for the BRP with LNG, schedule 400 MW of gas-fired generation in F2020 to serve Expected LNG load
> - meet interim energy and capacity shortfalls prior to Site C with cost effective market purchases first and power from the Columbia River Treaty second
> - fill in the energy shortfalls beyond Site C with cost-effective clean and renewable supply-side resources, as required
> - fill in the capacity shortfalls beyond Site C with cost-effective supply-side resources, as required. In doing so, the focus was first on clean resources such as Revelstoke 6 that are the most cost-effective capacity options, secondly on gas-fired generation allowed under the 7 per cent non-clean headroom, and then on pumped storage (underlining added)

20. Thus, the IRP states clearly that the methodology underlying its Recommended Actions is to "meet interim energy and capacity shortfalls prior to Site C with cost effective market purchases first". Clearly, in preparing its IRP, BC Hydro did not see this methodology as violating its obligations under the SSR.

21. Now, let us look at the year-by-year plan that flowed from this methodology. In Table 5 of the same document, on page 9A-10, BC Hydro presents the year-by-year Base Resource Plan with LNG (for energy). In the 3rd block of row headings ("Future Supply-Side Resources"), in the fourth row, we find Site C. The table shows Site C energy production starting in F2023 (388 GWh), increasing to 4,435 GWh F2024, and reaching 5,100 GWh starting in F2025.

22. In the last line of this same block, we find "Market Purchases". They are zero in most years, but are 245 GWh in F2022 and 474 GWh in F2023. Thus, we see that BC Hydro planned to meet these "interim energy shortfalls" with "cost effective market purchases". There is no indication that BC Hydro saw this strategy as in any way inconsistent with its self-sufficiency obligations under the *Clean Energy Act.*

23. In Table 9, on Page 9A-18 of the same document, we find a similar table for the Contingency Resource Plan, with LNG. As indicated in Section 2 of the same document, this scenario is based on

higher load growth and lower DSM performance. The strategies used include, again, “meet remaining interim and capacity shortfalls prior to Site C with cost effective market purchases first”.

24. Table 9 has exactly the same structure as Table 5. In the “Market Purchases” line, however, we see substantial purchases every year from F2014 through F2023. Except for one year, these purchases are all **more than 1,250 GWh per year**. In one year (F2019), they reach **4,144 GWh**.

25. Furthermore, the updated Energy and Capacity Summaries provided by BC Hydro in December 2014 (found in Attachment 6 to my Report) demonstrate energy shortfalls for the years F2019 through F2022, rising to 1,218 GWh in F2022 (Table 2 on page 22 of my Report, showing an energy balance of -1,218 GWh in F2022). Again, no mention was made by BC Hydro that relying on market purchases to meet such an interim shortfall, as called for in the IRP, was in conflict with the SSR.

26. In my Report, that same Table 2 shows that, with a one- or two-year delay, these interim shortfalls would be extended by one or two years, in the amounts of 1,669 GWh in the first year and 1,982 GWh in the second year (in the event of a two-year delay). These amounts are only somewhat greater than the amount that BC Hydro was expecting to purchase in F2022, and they are vastly less than those found in the Contingency Resource Plans of the IRP.

27. BC Hydro’s willingness to plan for purchases of over 1,000 GWh in its updated BRP, and for over 4,000 GWh in its CRP, effectively disposes of Mr. Savidant’s suggestion in paragraphs 107 and 108 that my reliance on market purchases is unjustifiable, from a reliability perspective.

28. The picture is similar from a capacity perspective. Table 6 (p. 12) of Appendix 9A shows, for the BRP with LNG, Market Purchases (in the section “Supply Not Requiring Reserves”) of 168 MW and 310 MW for F2022 and F2023, respectively. The similar line of Table 10 (CRP with LNG) shows market purchases in every year from F2016 through F2023, reaching a maximum of 583 MW in F2017. These shortfalls are similar in magnitude to those found in Table 1 (page 22) of my Report, of 349 MW and 472 MW, respectively, in F2023 and F2024.

Coherence with the SSR

29. In paragraph 103, Mr. Savidant states that my approach ignores the SSR. This is incorrect.

30. In paragraph 104, Mr. Savidant points out that the BC Government has the power to provide exceptions to the self-sufficiency regulation. (To be more precise, under s. 6(3) of the *Clean Energy Act*, the Government has the power to provide exceptions to the self-sufficiency requirement set out in s. 6(2) thereto.) He suggests, without actually so stating, that the scenarios I describe would be in conflict with the SSR. This is not the case.

31. To understand why, it is instructive first to understand the justification for the market purchases presented in the IRP.

32. First, regarding the capacity shortfalls in the BRP. Explicit mention is made of this, in footnotes 1 and 23 of Chapter 4, both of which refer to Section 9.2.7 (Recommended Action 7), on pages 9-39 and 9-40 of the IRP. The cost of this option is justified in Section 9.2.7.1 ("The market and CE capacity option-related costs are expected to be incidental business expenses."). In s. 9.2.7.3 ("Future approval process"), it is indicated that BC Hydro expects to obtain a regulation under s. 6(3) of the CEA authorizing this exception to the SSR.

33. Thus, BC Hydro proposed and the Government accepted an Integrated Resource Plan premised on the issuing of a future Order in Council under s. 6(3) of the *Clean Energy Act* by the LGIC.

34. It is interesting to note that there is no explanation in the IRP of the consistency of the planned market <u>energy</u> purchases in the BRP (245 GWh in F2022 and 474 GWh in F2023, as noted above in paragraph 22, increasing to over 1,200 GWh in the updated Summaries, noted in paragraph 25). BC Hydro apparently considered them to be not sufficiently significant an infringement on the SSR to require an authorizing regulation.

35. As for the Contingency Plans, it appears that these are not covered by the SSR, because the Self-Sufficiency Regulation "prescribes the mid load forecast as the forecast to be used for the purpose of determining the self-sufficiency requirement" (quoted from paragraph 103(b) of Mr. Savidant's affidavit). Thus, since the CRP reflects a scenario with load growth greater than the IRP's medium load growth scenario, the SSR does not apply to it.

36. This highlights an important subtlety of the s. 6(3) of the *Clean Energy Act* and of the Self-Sufficiency Regulation. S. 6(2) of the *Clean Energy Act* appears to be setting out an obligation that would constrain BC Hydro, in real time, for each year after 2016:

> (2) The authority must achieve electricity self-sufficiency by holding, by the year 2016 and each year after that, the rights to an amount of electricity that meets the electricity supply obligations solely from electricity generating facilities within the Province, …

37. However, the definition of "electricity supply obligations", set out in s. 6(1) is in fact based on BC Hydro's <u>forecasts</u>, as found in an integrated resource plan, not on its actual real time year-to-year supply needs:

> **6** **(1)** In this section:
> **"electricity supply obligations"** means
> (a) electricity supply obligations for which rates are filed with the commission under section 61 of the *Utilities Commission Act*, and
> (b) any other electricity supply obligations that exist at the time this section comes into force, <u>determined by using the authority's prescribed forecasts</u> of its energy requirements and peak load, taking into account demand-side measures, <u>that are in an integrated resource plan</u> approved under section 4; (underlining added)

38. Section 2 of the Self-Sufficiency Regulation further defines the "prescribed forecasts" to be BC Hydro's "mid-level" (medium load) forecasts.

39. While I am not a lawyer, it appears clear to me that the obligation created by s. 6(2) CEA constraints BC Hydro's planning process, not its real-time operations, since the "electricity supply obligations" that must be met "solely from electricity generating facilities within the Province" are those of the mid-level load forecast in its Integrated Resource Plan, not its actual real-time electricity needs.

40. This would further explain why the 400 MW of Market Reliance for Reserves on F2014 and F2015, found in the BRP for Capacity (Table 10 on page 20 of Appendix 9A of the IRP) does not require an exception to the SSR. As indicated by the vertical dashed red line shown on the table, it occurs during the Operating Period (F2014 through F2016), not the Planning Period (F2017 through F2033).

41. In accepting the 2013 Final IRP (Exhibit I to Mr. Savidant's Affidavit), the BC Government apparently deemed it to be in compliance with the SSR, despite a) relying without comment on market purchases of several hundred GWh in two years under the BRP with Expected LNG, and b) planning on requiring a regulation from the LGIC authorizing capacity market purchases in F2022 and F2023.

42. The next IRP, to be approved by 2018, will also need to be in conformity with the SSR (assuming that it remains in effect).

43. Presumably, that approval could also take into account a) minor energy shortfalls, and/or b) significant shortfalls that would require LGIC authorization.

44. It should also be noted that the Joint Review Panel specifically raised questions about the wisdom of maintaining the SSR in its current form. At page 304 of it Report (Exhibit J of Mr. Savidant's Affidavit #2), the Panel wrote that:

> Taken literally, this [the Self-Sufficiency Requirement] means a B.C. disconnected to the outside world, a vision of autarchy truly strange for a province that relies on trade, and a long way from its recent history. (It could also explain the neglect of geothermal opportunities.)
>
> Minor relaxations could mean being connected for reliability or for diversity exchange, which are current practices apparently not condoned by the regulation, or for multi-year balances, all of which seem consistent with the intent if not the drafting of the regulation. A definition consistent with the legislative intent could be that self-sufficiency means enough energy and capacity to serve BC Hydro's B.C. markets on a rolling five-year average, and to support and be supported by its Western Energy Coordinating Council partners for reliability. This would have the effect of modestly lowering the firm supply requirement, better integrating the otherwise allowable natural gas headroom and energy purchase agreements, and might allow better taking advantage of expected low market rates.

45. Given these options, there is no reason to believe that, should the 2018 IRP reflect the assumptions set forth in my Report, that it would be deemed to be inconsistent with the SSR.

Need to build new resources

46. As noted above at paragraph 12, at paragraph 109 of his affidavit Mr. Savidant asserts that, if the degree of market reliance in my report were to be found unacceptable, "it would be necessary to build new resources to fill demand requirements for the period of delay". This is incorrect for a number of reasons.

47. BC Hydro's energy and capacity balance includes several types of resources that are flexible and can be ramped up or down, depending on expected energy and capacity needs. These include, notably, electricity purchase agreements (EPAs) and demand-side management (DSM).

48. As of October 1, 2015, BC Hydro had 105 Electricity Purchase Agreements with IPPs whose projects are currently delivering power to BC Hydro, representing 18,902 gigawatt hours of annual supply and 4,606 megawatts of capacity. The details of these EPAs are listed in the document, **Independent Power Producers (IPPs) currently supplying power to BC Hydro,** attached to these comments as **Exhibit B**.

49. Also as of October 1, 2015, BC Hydro had 23 EPAs in development, representing 3,098 gigawatt hours of annual supply and 754 megawatts of capacity, as seen in the document entitled **Independent Power Producers (IPPs) with projects currently in development,** attached to these comments as **Exhibit C**.

50. BC Hydro has considerable flexibility with respect to the renewal or extension of these EPAs. In its Final 2013 IRP, it estimated that about 50 per cent of the bioenergy EPAs would be renewed, that about 75 per cent of the small hydroelectric EPAs that are up forrenewal in the next five years would be renewed, and that all remaining EPAs would be renewed (page 4-15, line 15 through page 4-16, line 3 of the IRP, Attachment 1 of my Report).

51. Furthermore, BC Hydro holds many contracts under the Standard Offer Program (SOP), described at pages 4-17 through 4-19 of the Final IRP. In the IRP, it presumed that 70% of these contracts would be renewed, resulting in energy supplies ranging from 557 GWh in F2022 to 1,431 GWh in F2033 (Table 4-9 on page 4-18 of the IRP). Capacity values are shown in Table 4-10 on page 4-19.

52. DSM is also a flexible resource that can be directly influenced by BC Hydro. In the IRP, BC Hydro considered several different levels of the DSM effort, with implications both on costs and on the energy and capacity balance. In the IRP, it recommended reducing DSM targets in F2017 through F2020, in order to reduce near-term expenditures. These changes are described on page 4-19 through 4-23 of the IRP, and the implications of the recommended changes are shown in Tables 4-12 and 4-13 on page 4-23.

53. These are all flexible resources. BC Hydro can increase or decrease the amount and duration of EPA and SOP renewals, as well as the extent of its DSM efforts, in order to decrease energy and capacity shortfalls that may flow from a delay in the commissioning of Site C.

54. Evaluating the cost implications of these alternatives is not possible within the time available to me to provide these Comments. However, there is no doubt that the costs of modulating these resources would be lower than the costs of developing new long-term supply resources, as Mr. Savidant indicated in paragraph 109 of his affidavit it would be necessary to do, in the event the degree of market reliance suggested in my report were determined to be unacceptable. His conclusions in paragraph 109 should therefore be disregarded.

BC Hydro's newly updated Load Resource Balance

55. On February 18, 2016 (subsequent to the submission of my Report), BC Hydro filed an **Evidentiary Update on Load Resource Balance and Long Run Marginal Cost** with the BC Utilities Commission. A copy is attached to these Comments as **Exhibit D**.

56. This updated LRB shows a substantial reduction in the medium load forecast, compared both to the one in the IRP and the one underlying the 2014 Energy and Capacity Summaries (Attachment 6 to my Report).

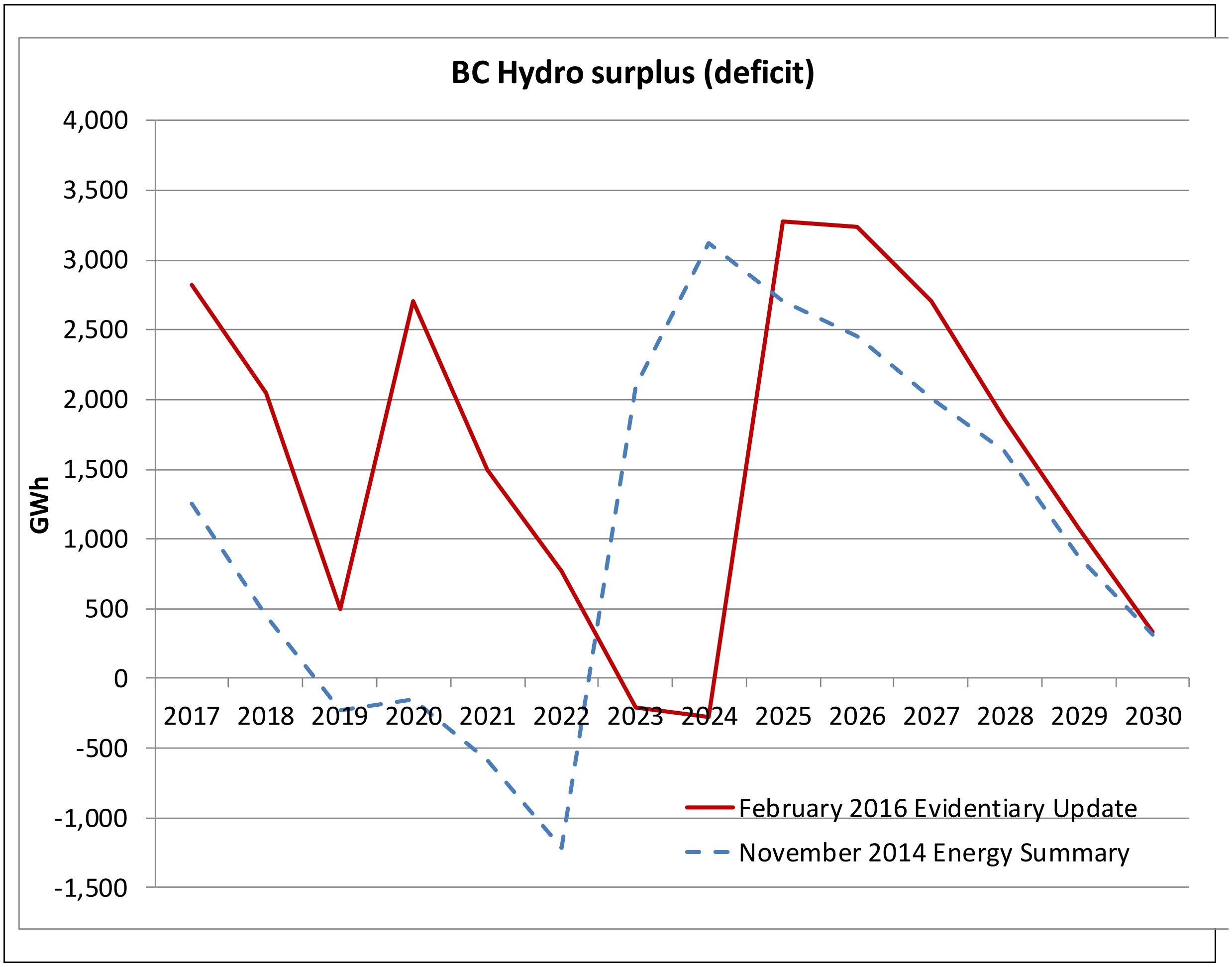
57. It also includes a planned reduction in expected EPA renewals:

> "Consistent with the 2013 IRP [sic], BC Hydro continues to plan to acquire through renewed EPAs 50 per cent of the energy and capacity contributions of existing bioenergy EPAs and 75 per cent of the contributions of the existing run-of-river hydroelectric EPAs that are due to expire by F2024."

58. This statement is not in fact consistent with the 2013 IRP, which, as we have seen in paragraph 50 above, anticipated renewals of 100% of the small hydro EPAs after 2018. That is, BC Hydro has now downgraded its anticipated EPA run-of-river hydroelectric renewals, presumably to reduce the expected surplus mentioned above. This increases the flexible resources available to BC Hydro.

59. To summarize, this updated Load Resource Balance reduces forecasted load, and increases the surpluses following commissioning of Site C.

60. In the following chart, I show the annual surplus (deficit) under the BC Hydro update released just before the Project was approved in 2014 (the dashed blue line), and under the February 2016 Evidentiary Update (the solid red line). We see that, under the current Evidentiary Update, the deficit just before Site C commissioning has been greatly reduced (from 1,218 to 276 GWh), and the surplus following commissioning remains high for a longer period.



61. Time does not permit me to update all the quantitative analyses in my Report, based on these new data. It is clear, however, that doing so would result in substantially **decreasing the costs** and **increasing the benefits** of delaying the commissioning of Site C.

Cost of a two-year delay

62. At paragraph 115 of his affidavit, Mr. Savidant states that my assumption that the cost of a one-year delay would double for a two-year delay is unsubstantiated. This is true, as he has not presented any estimate of that cost, and I do not have access to the financial model or the other information required to make such an estimate. However, I maintain that, under the circumstances, this assumption is not unreasonable.

63. In paragraphs 113 and 114, Mr. Savidant mentions several elements that could result in a higher cost for a two-year delay. However, he fails to mention the elements that could in fact result in those costs being lower.

64. In paragraphs 5(a)(v) and 6(a)(i) of his Affidavit #1, Mr. Savidant included the costs of demobilization and remobilization in his initial estimate. These costs are also mentioned in paragraph 52 of his Affidavit #2. I understand that these costs can be substantial.

65. However, there is no reason to expect the demobilization and remobilization costs for a particular contract to double for a two-year delay as opposed to a one-year delay. While there may be additional carrying and maintenance costs due to the additional delay, work would not be remobilized and then demobilized a second time.

66. The discussion of the cost implications of a two-year delay in paragraphs 113 and 114 thus appear to be incomplete and one-sided.

67. Mr. Savidant chose not to present an actual estimate of the costs related to a two-year delay in his Affidavit #2. Instead, he simply presented a table (at paragraph 116) showing the cost implications if those costs were to exceed the values I used by a "premium" of 10%, 25% or 50%. He offers no reason to believe that any of these premiums would be justified, nor does he in any way rule out the possibility that costs of a two-year delay could be less than double those of a one-year delay by similar percentages.

Annual cost of the Site C Project

68. At paragraph 118, Mr. Savidant indicates that the method I used to estimate the annual cost of the Site C Project fails to reflect its true cost under the Government's 10-year Rate Plan.

69. He explains at paragraph 119(a) that, under this Plan, "the amount of net income that BC Hydro is required to earn each year will be tied to inflation after 2018, and will no longer increase when new assets like Site C are added to the system."

70. In paragraph 119(c), he adds that, under the Plan, the annual financing cost of Site C would be approximately equal to the cost of the debt, about 4.5% per year "for the extended forecast period".

71. In effect, then, the BC Government would recover only the cost of debt (4.5%) for its equity investment in Site C, foregoing the normally higher return on equity.

72. These statements suggest that the financing arrangements set out in the 10-year Rate Plan are permanent. There is no justification whatsoever for this position. First, these arrangements are not set out either in legislation or in regulations, but only in a government Plan. They are thus in no way binding on future governments, or even on the present government – and it is unlikely that the present government will still be in place when Site C is commissioned in 2024 or later.

73. More important, even if it were binding, the Plan is a <u>10-Year</u> Rate Plan. Announced in November 2013, it would remain in effect from 2014 through 2023 – ending just **before** Site C is commissioned.

74. As quoted above, Mr. Savidant states that, under the 10-year Rate Plan, "the amount of net income that BC Hydro is required to earn each year will be tied to inflation after 2018, and will no longer increase when new assets <u>like Site C</u> are added to the system." If it remains in effect for the full ten years, it will indeed affect the costs of new assets which are added to the system during that period. However, it would have no effect whatsoever on the costs of new assets, like Site C, that would be added <u>after</u> the 10-year Rate Plan expires.

75. Indeed, he should have written, "the amount of net income that BC Hydro is required to earn each year will be tied to inflation after 2018 <u>until 2023</u> …", since the Plan is set to expire in that year.

76. At paragraph 124(b), Mr. Savidant criticizes my use of a constant annual cost over the life of the project. This approach, detailed at page 24 of my Report, was based on the Government Backgrounder Comparing the Options (Attachment 7 to my Report, and Exhibit K to Mr. Savidant's Affidavit #2, reproduced in Figure 5 in my Report), which shows annual costs for Site C varying within a narrow band over the 70-year life of the project.

77. In the same paragraph, Mr. Savidant indicates that the annual cost I used is approximately $70 million, or 10%, greater than BC Hydro's estimate. This difference is likely due, in large part, to BC Hydro's incorrect use of the cost of debt (4.5%) as the annual financing cost of Site C "for the extended forecast period," despite the fact that the 10-year Rate Plan will expire before Site C comes on line. There is thus every reason to believe that the cost to BC Hydro ratepayers of the government equity in the Site C project will be determined in accordance with standard regulatory procedures.

78. For the reasons described above, I find that Mr. Savidant's conclusions at paragraph 99 and at paragraphs 125 through 129 to the effect that my assumptions are incorrect and my conclusions invalid should be disregarded.

79. There is nothing in Mr. Savidant's affidavit to contradict the conclusion in my Report to the effect that, given the very substantial and unavoidable uncertainties in every element of these projections, the additional costs of delay identified in the Savidant affidavit, when combined with the very substantial positive ratepayer impacts that delay would produce prior to commissioning and in the first decades thereafter, are highly uncertain and not significant.

80. This result reflects the fact that delaying commissioning will tend to reduce the losses that result from selling Site C surplus power in the export market at prices far below its production cost. This benefit tends to counterbalance the increased capital cost resulting from the delay. Whether the net result is slightly positive or slightly negative depends on the evolution into the distant future of

parameters such as market prices, exchange rates and interest rates, the future values of which are highly uncertain and effectively unknowable.

81. I certify that I am aware of my duty as an expert witness under the British Columbia Supreme Court Civil Rules to assist the court and not to be an advocate for any party. The attached report has been made in conformity with that duty. If I am called on to give testimony, I will do so in conformity with that duty.

EXHIBIT A

Integrated Resource Plan

Chapter 9

Recommended Actions

Table of Contents

List of Figures

List of Tables

9.1 Introduction

This chapter presents BC Hydro's 18 Recommended Actions to ensure that BC Hydro can reliably and cost-effectively supply its customers' load requirements under expected (or base) conditions through Base Resource Plans (**BRPs**) and contingency conditions through Contingency Resource Plans (**CRPs**).

BC Hydro developed two BRPs: one that contains Recommended Actions prior to considering load growth from Expected Liquefied Natural Gas (**LNG**) and one that contains the incremental Recommended Actions to address the Expected LNG requirements. Expected LNG load warrants specific analysis and associated recommendations given the potential large size of this identifiable load. Presenting the BRP prior to LNG is consistent with the treatment of the load-resource balance (**LRB**) in the Site C Environmental Impact Statement (**EIS**). These actions will be required regardless of the level of LNG load that BC Hydro supplies.

BC Hydro develops CRPs to address load growth and resource uncertainty, including those associated with the delivery of transmission resources. There are two CRPs to address contingencies without Expected LNG load (**CRP1**) and with Expected LNG load (**CRP2**).

The Recommended Actions meet BC Hydro's energy and capacity planning criteria (discussed in section 1.2.2), and align with the British Columbia's energy objectives in section 2 of the *Clean Energy Act* (***CEA)*** as described in section 1.2.3 of this Integrated Resource Plan (**IRP**). Chapter 8 describes the Clean Energy Strategy and the associated Recommended Action 10 that have been developed in response to the request from the Minister of Energy and Mines (**Minister**) for BC Hydro to support the clean energy sector and promote clean energy opportunities for First Nations, and comments received during BC Hydro's last IRP consultation. Recommended Action 10 has been captured in the BRP without LNG section, but while some of the actions comprising the Clean Energy Strategy are reflected in the BRP (such as increasing the Standing Offer Program (**SOP**) target), other actions are preparatory in nature that support the CRPs. Chapter 7 reviews the consultations with First Nations and stakeholders during development of the IRP and the May 2012 Draft IRP. Chapter 7 also provides BC Hydro's response to consultation input to date and a reflection on the extent to which the Recommended Actions contained in this IRP align with these consultations.

For each Recommended Action, BC Hydro:

1. Summarizes the justification found elsewhere in the IRP such as Chapters 4, 6, and 8
2. Sets out the anticipated expenditures. The expenditures are generally provided for the F2014 to F2016 period for each Recommended Action. Longer-term expenditures for large initiatives such as implementing the Demand Side Management (**DSM**) target, and capital costs for projects such as Site C are also provided
3. Lists the steps to be taken over the next five years to advance the specific project or initiative including: a) risk mitigation measures; and b) potential major regulatory review processes and other trigger events.

As described in Chapters 2, 4 and 6, economic conditions, developments in the mining and gas sectors, the timing and scope of new LNG requirements, and continued uncertainty in the delivery of DSM energy and associated capacity savings contribute to significant uncertainty in the need for new resources. Many of the Recommended Actions are designed to, among other things, keep options open so that BC Hydro can reliably and cost-effectively meet need, while providing off-ramps should the need change.

Approval of the IRP does not by itself lead to implementation of the Recommended Actions. For example, implementing the proposed capital projects entails securing government agency and regulatory approvals, and undertaking additional First Nations consultation and public engagement processes, as required. Pursuing DSM initiatives requires various forms of approval by the British Columbia Utilities Commission (**BCUC**). Thus the IRP provides the long-term planning context for future applications and associated review processes.

9.1.1 Recommended Action Summary

The BRP before Expected LNG addresses the energy and capacity load-resource gaps from F2017 onward set out in section 2.4, after reflecting the DSM Target and Electricity Purchase Agreement (**EPAs**) portfolio cost management initiatives discussed in Chapter 4. This BRP is based on, among other things, the December 2012 mid Load Forecast.

The LNG BRP addresses the incremental LNG expected load of 3,000 GWh/year and 360 MW as discussed in section 2.2.

CRP1 addresses contingencies without Expected LNG load, and CRP2 addresses contingencies with Expected LNG load.

Table 9-1 provides an overview of the 18 Recommended Actions for the BRP, LNG BRP and CRPs.

Table 9-1 IRP Recommended Action Description

Category	IRP Recommended Action	
BASE RESOURCE PLAN		
DSM (Conservation)	1. Moderate current spending and maintain long-term target	Target expenditures of $445 million on conservation and efficiency measures during the fiscal years 2014 to 2016. Prepare to increase spending to achieve 7,800 gigawatt-hours per year in energy savings, and 1,400 MW in capacity savings, by F2021.
	2. Pursue DSM capacity conservation	Implement a voluntary industrial load curtailment program from F2015 to F2018 to determine how much capacity savings can be acquired and relied upon over the long term.
	3. Explore more codes and standards	Explore additional opportunities to leverage more codes and standards to achieve conservation savings at a lower cost and to gain knowledge and confidence about their potential to address future or unexpected load growth.
Portfolio Cost Management	4. Optimize existing portfolio of IPP resources	Optimize the current portfolio of IPP resources according to the key principle of reducing near-term costs while maintaining cost-effective options for long-term need.
	5. Investigate customer incentive mechanisms	Investigate incentive-based pricing mechanisms over the short term that could encourage potential new customers and existing industrial and commercial customers looking to establish new operations or expand existing operations in BC Hydro's service area.
Supply-Side Resources	6. Continue to advance Site C	Build Site C to add 5,100 GWh/year of annual energy and 1,100 MW of dependable capacity to the system for the earliest in service date (**ISD**) of F2024 (for all six generating units) subject to: environmental certification; fulfilling the Crown's duty to consult, and where appropriate, accommodate Aboriginal groups; and B.C. Government approval to proceed with construction.
	7. Pursue bridging options for capacity	Fill the short-term gap in peak capacity with cost-effective market purchases first and power from the Columbia River Treaty second.
Transmission Resources	8. Advance reinforcement along existing GMS-WSN-KLY 500 kV transmission line	Advance reinforcement of the existing GM Shrum-Williston-Kelly Lake 500 kV transmission lines to be available by F2024.
	9. Reinforce South Peace transmission	Review alternatives for reinforcing the South Peace Regional Transmission Network to meet expected load.
Supply-Side Resources	10. Support Clean Energy Strategy	Advance a set of actions that will support a healthy, diverse clean energy sector and promote clean energy opportunities for First Nations' communities

Category	IRP Recommended Action	
LNG BASE RESOURCE PLAN		
Supply-Side Resources	11. Explore natural gas-fired generation for the North Coast	Working with industry, explore natural gas supply options on the north coast to enhance transmission reliability and to meet the expected load.
	12. Explore clean energy supply options, if LNG demand exceeds available resources	Explore clean or renewable energy supply options and be prepared to advance a procurement process to acquire energy from clean power projects, as required to meet LNG needs that exceed existing and committed supply.
Transmission Resources	13. Advance reinforcement of the transmission line to Terrace	Advance reinforcement of the existing 500 kV transmission line from Prince George to Terrace, which includes development of three new series capacitor stations and improvements in the existing BC Hydro substations to be available by F2020.
Other	14. Explore supply options for Horn River Basin and northeast gas industry	Continue discussions with B.C.'s northeast gas industry and undertake studies to keep open electricity supply options, including transmission connection to the integrated system and local gas-fired generation.
CONTINGENCY RESOURCE PLAN		
Supply-Side Resources	15. Advance Revelstoke Unit 6 Resource Smart project	Advance the Revelstoke Generation Station Unit 6 Resource Smart project to preserve its earliest in-service date of F2021 with the potential to add up to 500 megawatts of peak capacity.
	16. Advance GM Shrum Resource Smart project	Advance Resource Smart upgrades to GM Shrum Generating Station Units 1–5 with the potential to gradually add up to 220 MW of peak capacity starting in F2021.
	17. Investigate natural gas-fired generation for capacity	Working with industry, explore natural gas supply options to reduce their potential lead time to in-service and to develop an understanding of where and how to site such resources, should they be needed.
Other	18. Investigate Fort Nelson area supply options	Investigate procurement options to serve future Fort Nelson load.

9.1.2 Action Plan Alignment with BRP & CRP Scenarios

Table 9-2 is a summary of how the Recommended Actions are developed to align to the BRP, the BRP for Expected LNG load, and the two CRPs.

Table 9-2 IRP Recommended Action Category Summary

IRP Recommended Action		Category	BRP	LNG BRP	CRP1 and CRP2
1	BC Hydro DSM Target	**DSM (Conservation)**	□		
2	DSM Capacity Options	**DSM (Conservation)**	□		
3	DSM Codes and Standards Support	**DSM (Conservation)**	□		
4	IPP EPA Portfolio	**Portfolio Cost Management**	□		
5	Customer Incentive Mechanisms	**Portfolio Cost Management**	□		
6	Site C	**Supply-Side Resources**	□		
7	Bridging Capacity from Market Resources	**Supply-Side Resources**	□		
8	Existing GMS-WSN-KLY 500 kV Transmission Corridor	**Transmission Resources**	□		
9	South Peace Transmission	**Transmission Resources**	□		
10	Support Clean Energy Strategy	**Supply-Side Resources**	□		□
11	Natural Gas-Fired Generation for the North Coast	**Supply-Side Resources**		□	
12	Clean or Renewable Energy for High LNG Demand	**Supply-Side Resources**		□	
13	Reinforcement of 500 kV Line to Terrace	**Transmission Resources**		□	
14	Horn River Basin and Northeast Gas industry	**Other**		□	
15	Revelstoke Unit 6	**Supply-Side Resources**			□
16	GMS Units 1-5 Capacity Increase	**Supply-Side Resources**			□
17	Natural Gas-Fired Contingency Options	**Supply-Side Resources**			□
18	Fort Nelson Supply	**Other**			□

9.1.3 Chapter Structure

The remainder of this chapter is laid out as follows:

- Section 9.2 describes the ten BRP Recommended Actions without Expected LNG load, shows the energy and capacity LRBs after implementation of the ten Actions, and provides BC Hydro's Long Run Marginal Cost (**LRMC**) for the period F2014 to F2033. The Clean Energy Strategy Recommended Action 10, as described in Chapter 8, contains elements that support of the BRP as well as preparatory actions that support the CRPs.
- Section 9.3 describes the four BRP Recommended Actions to address Expected LNG load, with an emphasis on a flexible and staged approach to address LNG load uncertainty
- Section 9.4 provides a description of the four Recommended Actions associated with BC Hydro's two CRPs, along with a summary of the foundation for the CRPs
- Section 9.5 contains additional recommendations relating to: electrification, export market analysis, transmission planning for generation clusters, and the future IRP submission cycle.

9.2 Base Resource Plan

BC Hydro's BRP before Expected LNG provides a 20-year view of the portfolio of generation and transmission resources needed to address the energy and capacity load-resource gaps depicted in section 2.4. The ten BRP Recommended Actions will allow BC Hydro to meet its current and future customers' electricity needs on a reliable and cost-effective basis.

To ensure fair and open access to the transmission system, BC Hydro has a number of procedures governed by its Open Access Transmission Tariff (**OATT**), including the use of a queue to ensure transmission service requests are dealt with in a 'first-come, first-served' manner. Once the IRP is approved, BC Hydro will submit this BRP and the LNG BRP described in section 9.3 as transmission service requests under the OATT tariff. Transmission requests for contingency plans are discussed in section 9.4.

This section includes the following subsections:

- Subsections 9.2.1 to 9.2.9 present the ten BRP Recommended Actions, along with their justification, their execution plan and risk mitigation, and their respective future approval processes
- Subsection 9.2.11 depicts the energy and capacity LRBs that will result from successful implementation of the nine BRP Recommended Actions
- Subsection 9.2.12 summarizes BC Hydro's energy and capacity LRMCs for the period F2014 to F2033.

9.2.1 Recommended Action 1: Moderate current DSM spending and maintain long-term target

Target expenditures of $445 million ($175 million, $145 million, and $125 million per year) on conservation and efficiency measures during F2014 to F2016. Prepare to increase spending to achieve 7,800 GWh/year in energy savings, and 1,400 MW in capacity savings, by F2021.

The Recommended Action is to continue working toward BC Hydro's current DSM target originally established in the 2008 LTAP. The remaining savings of the original target is 7,800 GWh by F2021. This is equivalent to reducing new electricity demand by approximately 78 per cent over that period without Expected LNG load (the corresponding figure with Expected LNG load is about 69 per cent). The DSM plan to achieve that target would involve investment in DSM programs at about the same rate as has been done over the past four years, but which is reduced from the previous DSM plan shown in the F2012-F2014 Revenue Requirements Application (**RRA**), as described in Chapter 4.

Implementation of the DSM plan as currently conceived to achieve the DSM target is forecast to save approximately 7,000 GWh/year and 1,300 MW by F2021, with losses:

- While the current DSM plan F2021 savings are somewhat lower than the target, in the following years the DSM plan is expected to result in the same level of savings as that target
- The DSM target of 7,800 GWh/year is a P50, which is a mid-level estimate established in the 2008 LTAP, and as such, some variation between current plan savings and the target is expected. As described in Chapter 4, DSM energy savings for Option 2/DSM Target are P50 estimates and there is uncertainty with over or under-delivery of energy savings represented by the high and low forecasts. The difference between the planned and targeted energy savings in F2021 is within a reasonable variance (i.e., +/- 10 per cent) and is within 2 per cent of the DSM target levels by the Site C earliest ISD of F2024.

Depending on actual DSM performance, expenditures and program activity levels can be adjusted in future years. For this section 9.2.1, energy savings, associated capacity savings and expenditures are based on the plan to achieve the DSM target.

The utility cost (**UC**), which is the implementation cost of pursuing the DSM target over the period of F2014 to F2016 is estimated to be approximately $445 million. Table 9-3 below summarizes the UC by component type.

Table 9-3 Utility Cost of DSM Target ($ million) (cumulative over the years indicated)

	3 years: F2014 to F2016	8 years: F2014 to F2021	20 years: F2014 to F2033
Codes and Standards	9	24	67
Rate Structures	10	21	51
Programs – Total			
• Programs – Residential	56	154	470
• Programs – Commercial	131	382	1,271
• Programs – Industrial	173	465	1,220
Programs – Sub-total	360	1,001	2,961
Supporting Initiatives	67	182	512
Total	445	1,228	3,591

The DSM plan will have approximately $6.5 billion in aggregate customer bill savings over the 20-year period.

The energy and associated capacity savings in F2021 from implementation of the plan to achieve the recommended DSM target are set out in Table 9-4 and Table 9-5 respectively.

Table 9-4 DSM Implementation Plan: Cumulative Energy Savings since F2013 at Customer Meter in F2021

	Codes and Standards (GWh/year)	Rate Structures (GWh/year)	Programs (GWh/year)	Total (GWh/year)
Residential	1,639	472	339	2,449
Commercial	617	356	778	1,751
Industrial	84	304	1,717	2,105
Total	2,340	1,132	2,834	6,306

Table 9-5 DSM Implementation Plan: Cumulative Capacity Savings since F2013 in F2021 at Customer Meter

	Codes and Standards (MW)	Rate Structures (MW)	Programs (MW)	Total (MW)
Residential	423	101	66	590
Commercial	123	49	106	278
Industrial	9	39	195	243
Total	555	189	367	1,111

9.2.1.1 Justification

The plan to achieve the DSM target is technically feasible, cost-effective as measured by total resource cost (**TRC**) and UC, and achievable.

As is apparent from Table 9-6, codes and standards and conservation (stepped) rate structures have the lowest UC. BC Hydro's expenditures in support of codes and standards are justified on the grounds that they are cost-effective even if only 1 per cent of savings are attributable to BC Hydro's efforts. BC Hydro is confident that its expenditures in support of codes and standards will be critical to the achievement of considerably more than 1 per cent of the savings.

Beginning in April 2006, BC Hydro implemented four conservation rates with inclining block (stepped) rate structures for residential, commercial and industrial customers. Given the LRMC described in section 9.2.12, BC Hydro is in the process of revisiting the stepped rate pricing signals starting with the Residential Inclining Block (**RIB**) rate.[1] However, BC Hydro is not proposing a return to flat rates given: 1) there is a need for energy in F2017 without any further DSM initiatives; and 2) conservation rate structures are longer-term initiatives that are not easily re-introduced.

[1] The inclining block rate structure for BC Hydro's largest industrial customers, Rate Schedule 1823 (referred to as the Transmission Service Rate or **TSR**) is being examined as part of the Industrial Electricity Policy Review.

The remainder of this section focuses on the DSM program component of the DSM target.

Need: BC Hydro forecasts an energy gap and a capacity gap from F2017 onward. To address these gaps, BC Hydro looks first to DSM and the associated energy savings from codes and standards, stepped rate structures and programs. However, the tools employed to achieve the DSM target are integrated. Significant adjustments to any of the tools could impact the ability to achieve the planned level of energy savings delivered by the other tools.

As the activity level with programs is more flexible and easier to ramp up or down over shorter time periods, BC Hydro looks to adjust the DSM program component in the near term to reduce upward rate pressures, while still maintaining the flexibility to ramp up. This action is described below in section 9.2.1.2.

Cost-Effectiveness: Activities should be cost-effective to ensure BC Hydro's investments in DSM will generally be lower than the LRMC and reduce overall revenue requirements while providing broad opportunities for participation across customer sectors. Cost-effectiveness is measured by the TRC and UC.

As set out in Chapter 3, pursuing the plan to achieve the DSM target would deliver electricity savings at an average unit cost of approximately $32/MWh.[2] Table 9-6 below shows the cost-effectiveness of the plan to achieve the DSM target at both a tool and individual program level using the LRMC range of between $85/MWh and $100/MWh (described in section 9.2.12 below); and sets out the Net TRC and savings pertaining to DSM programs:

- All three DSM tools (codes and standards, rate structures and programs) encompassed by the plan to achieve the DSM target across all sectors have a TRC benefit-cost ratio greater than 1.0, which is the BCUC accepted standard

[2] The net DSM cost of $8/MWh reflects deemed natural-gas benefits and deemed non-energy benefits as defined in the DSM Regulation.

- Programs with a TRC benefit-cost ratio greater than 1.0 indicate the program costs are lower than the LRMC. With the exception of the DSM New Home program, and the Low Income program using a LRMC of $85/MWh, all programs have a TRC ratio of at least 1.0. The New Home program is expected to be substantially complete by F2015.
- With the exception of the Low Income program, all DSM tools encompassed by the plan to achieve the DSM target across all sectors have a UC benefit-cost ratio greater than 1.0. A benefit-cost ratio above 1.0 indicates that the program would lower BC Hydro revenue requirements and therefore the aggregate customer bill.

Table 9-6 DSM Implementation Plan – UC and TRC Benefit-Cost Ratios at Alternate LRMCs[3]

	LRMC at $100/MWh		LRMC at $85/MWh	
	UC Test	**TRC Test**	**UC Test**	**TRC Test**
Codes and Standards	**117.1**	**5.5**	**102.8**	**4.9**
Rate Structures	**16.4**	**10.0**	**14.3**	**8.8**
DSM Programs				
Residential Sector				
Behaviour	3.5	4.8	3.1	4.2
Refrigerator Buy-Back	1.5	2.1	1.3	1.8
Low Income	0.9	1.0	0.8	0.9
New Home	1.3	0.7	1.2	0.6
Residential Rebate	1.8	1.8	1.6	1.6
Renovation Rebate	2.5	1.2	2.2	1.1
Load Displacement	6.5	2.4	5.5	2.0
Residential Sector Total	*2.4*	*2.0*	*2.1*	*1.8*
Commercial Sector				
Power Smart Partner	1.9	1.7	1.6	1.5
Product Incentive	2.2	1.6	1.9	1.4
New Construction	2.2	1.4	1.9	1.2
Lead by Example	1.1	1.1	1.0	1.0
Load Displacement	2.5	1.4	2.1	1.2
Commercial Sector Total	*2.0*	*1.6*	*1.7*	*1.4*
Industrial Sector				
Power Smart Partner – Transmission	4.0	2.3	3.5	2.0
Power Smart Partner – Distribution	1.9	1.7	1.6	1.5
Load Displacement	3.2	2.9	2.8	2.5
Industrial Sector Total	*3.2*	*2.3*	*2.8*	*2.0*
Total Programs	**2.6**	**2.0**	**2.2**	**1.7**
Portfolio Total	**5.2**	**3.1**	**4.6**	**2.7**

[3] Benefit-cost ratios for rate structures and programs include supporting initiative costs. Supporting initiatives include public awareness and education, community engagement, technology innovation, information technology, and indirect and portfolio enabling.

Table 9-7 DSM Programs TRC and Savings

DSM Programs (sorted by net TRC)	*Net TRC ($/MWh)**	*Forecast Savings @ F2021 (GWh/year)*	*Cumulative Savings (GWh)*	*% of Total Cumulative Savings (%)*
Behaviour	6	135	135	5
Load Displacement - Ind	27	432	567	20
Power Smart Partner - Transmission	36	1,021	1,588	56
Load Displacement - Res	42	0	1,588	56
Refrigerator Buy-back	43	66	1,653	58
Residential Rebate	46	53	1,706	60
Power Smart Partner - Distribution	51	265	1,971	70
Power Smart Partner - Com	52	450	2,421	85
Product Incentive	55	173	2,594	92
New Construction	60	123	2,717	96
Load Displacement - Com	69	4	2,721	96
Lead by Example	71	28	2,749	97
Renovation Rebate	77	56	2,805	99
Low Income	88	20	2,825	100
New Home	113	8	2,834	100

* Net TRC shown is net of generation, transmission and distribution capacity benefits, non-energy benefits and natural gas savings benefits.

The plan to achieve the DSM target encompasses a comprehensive portfolio of DSM measures with a broad offering to all customer sectors designed to complement one another and capture synergies. Refer to section 9.2.1.2 for more detail concerning the percentage of BC Hydro's DSM program spend by customer sector for the F2014 to F2016 period. The DSM plan will result in approximately $6.5 billion in aggregate customer bill reductions. The DSM program component is flexible and can be changed over time in response to new information.

Environmental and Economic Development Benefits: DSM avoids the environmental impacts associated with the construction of new generation facilities. DSM provides economic development benefits through increased GDP and the direct creation of jobs for customers and trade allies from the implementation of energy savings initiatives. It also provides opportunities for customers to save money on their electricity bills and for industry to improve its competitiveness.

Policy Alignment: The DSM target aligns with several of the energy objectives contained in section 2 of the *CEA*, as discussed in section 1.2.3. A key *CEA* objective for DSM is the objective to reduce the expected increase in demand by at least 66 per cent by 2020 (*CEA* objective 2(b)). The DSM target achieves a 78 per cent reduction in the expected increase in demand without potential LNG load.[4]

9.2.1.2 Execution

BC Hydro is proposing to adjust expenditures for DSM programs over the next three years while maintaining the potential to achieve higher DSM savings in the long term. A primary challenge in adjusting DSM programs is ensuring that programs remain a viable, low-cost resource to address future energy and capacity gaps. In Chapter 4, BC Hydro examined two 'alternative means' (functionally different ways) of achieving the DSM target in F2021:

- DSM Alternative Means 1 (status quo – no DSM program expenditure reduction)
- DSM Alternative Means 2 (near-term expenditure reductions, ramping back up to the DSM target generally by F2021)

A potential third path to the DSM target was also explored, which would reduce expenditures further than Alternative Means 2 in the near term (to $100 million in F2016) and aggressively ramps up to higher levels of activity in F2017. However, even with the aggressive ramp-up rate, this path fails to return to the energy savings levels of the DSM target by F2021. There are additional energy savings delivery

[4] The DSM target achieves a 69 per cent reduction in demand if Expected LNG load is included.

risks associated with a further reduction of expenditures and the aggressive ramp-up rate.

BC Hydro recommends DSM Alternative Means 2. The planned adjustments to DSM program activities and expenditures in the near term result in potential savings of $330 million over F2015 to F2022 relative to Alternative Means 1. These reduced expenditures will result in almost 900 GWh/year of lower cumulative DSM energy savings by F2021. F2014 is a transition year as approximately $65 million in project incentives is already committed.

In developing these reduced expenditures and maintaining the ability to ramp up, BC Hydro employed the following principles: 1) eliminate projects or activities that have a short energy savings persistence and thus only contribute to the near-term surplus period; 2) consider ‘lost opportunities’ by (a) continuing to offer incentives for energy savings opportunities that will not be available in the future (e.g., one-time opportunities for incremental improvement to building envelope upgrades or new construction) and (b) defering incentives for energy savings opportunities that are not needed now but will have a predictable uptake regardless of when they are offered; 3) maintain program activities to retain a level of customer and trades engagement and relationships so that DSM programs can be ramped up to long-term savings targets as needed; 4) consider cost-effectiveness of DSM programs from both the UC and TRC perspectives; and 5) consider broad opportunities for customers to participate.

To maximize the range of ratepayers able to participate in DSM and benefit from lower bills, BC Hydro needs to strike a portfolio level balance between ensuring overall cost-effectiveness and equity. One example in this regard is the Low Income program. Consistent with stakeholder and First Nations consultation input, BC Hydro proposes to maintain the program and not reduce the offer. Other considerations include the availability of opportunities to each sector and the barriers in each market.

Table 9-8 sets out the percentage of BC Hydro's DSM program spend by sector for the F2014 to F2016 period and Table 9-9 sets out the energy savings delivered from each customer class. While residential expenditures are lower, they deliver a considerable amount of savings through codes and standards activity.

Table 9-8 Percentage of DSM Program Spend by Sector (F2014-F2016)

Residential (%)	Commercial (%)	Industrial (%)
16	36	48

Table 9-9 Percentage of DSM Energy Savings by Sector (F2021) (includes programs, codes and standards, and rate structures)

Residential (%)	Commercial (%)	Industrial (%)
39	28	33

Risk Mitigation: Over the medium and longer term, risk mitigation is aimed at two key risks: (1) deliverability of energy and capacity savings; and (2) costs to deliver those savings. DSM risk mitigation includes:

- **Initiative Design:** DSM initiatives are designed to consider risk. For example, DSM programs are designed to successfully attract customer participation based on information from market research, jurisdictional reviews and consultations with customers, retailers and trade allies
- **Incentive Design:** Several DSM programs use incentive structures that ensure BC Hydro provides an appropriate financial incentive for individual projects and limits the amount needed to achieve DSM electricity savings
- **Tracking Performance Metrics:** BC Hydro tracks program electricity savings and costs on a monthly basis. BC Hydro also tracks leading and lagging performance indicators for each DSM initiative.

- **Savings Estimates and Verification:** BC Hydro undertakes a comprehensive approach to estimate the electricity savings from each DSM initiative and periodically updates its savings information based on the results
- **Management Oversight:** Regular oversight is done at both the DSM initiative and plan levels. During the implementation of a program or initiative, risks are monitored through the tracking of indicators as described above. Management judgement, industry input and stakeholder feedback are then combined with these key performance indicators when assessing changes to programs and initiatives.
- **Plan and Initiative Adjustments:** Adjustments are made at the initiative and plan levels as required. For example, if a program is not performing as expected or if there is new information that could impact a program, adjustments can be made to the program.

BC Hydro also addresses DSM deliverability risk through the two CRPs set out in section 9.4.

9.2.1.3 Future Review Process

Implementation of the DSM target will require two applications to the BCUC in the next six months:

- **RIB:** BC Hydro submitted a RIB rate application to the BCUC in November 2013 pursuant to sections 58 to 61 of the *Utilities Commission Act* (***UCA***) to request approval of new pricing principles[5] that would apply for F2015 and F2016
- **DSM Expenditures for F2014 to F2016:** BC Hydro will file a DSM expenditure schedule for F2014 to F2016 pursuant to subsection 44.2(1)(a) of the *UCA* with the BCUC for acceptance with expenditures of $175 million, $145 million and

[5] A pricing principle is a high level guiding principle that determines how price changes are applied to individual elements of a rate.

$125 million for the three years. In considering whether to accept the DSM expenditure schedule for F2014 to F2016, the BCUC must, pursuant to subsection 44.2(5.1) of the *UCA*, consider the interests of persons in B.C. who receive or may receive service from BC Hydro; and consider and be guided by the applicable section 2 *CEA* British Columbia's energy objectives, an applicable approved IRP, and the extent to which the proposed DSM initiatives are cost-effective within the meaning of the DSM Regulation. BC Hydro has consulted with interveners as to the timing for the F2014 to F2016 DSM expenditure schedule filing and plans to file in February 2014 as part of or contemporaneously with the F2015/F2016 RRA.

9.2.2 Recommended Action 2: Pursue DSM capacity conservation

Implement a voluntary industrial load curtailment program from F2015 to F2018 to determine how much capacity savings can be acquired and relied upon over the long term. Pilot voluntary capacity-focused programs (direct load control) for residential, commercial and industrial customers over two years, starting in F2015.

While the DSM target described in section 9.2.1.1 has significant associated capacity savings of 1,400 MW in F2021, additional capacity savings may be possible through DSM capacity activities (also referred to as peak reduction, peak shaving or load shifting). Capacity-focused DSM is grouped into two broad categories:

- **Industrial Load Curtailment:** This DSM option targets customers who agree to curtail load on short notice provided by BC Hydro during peak periods. BC Hydro proposes to implement a voluntary load curtailment program with BC Hydro's industrial customers to be developed and implemented in stages between F2015 and F2018. Opportunities to accelerate the timeline may be discovered. This program will identify how much long-term capacity savings are available and can be relied upon for long-term planning purposes.

- **Capacity Programs:** This DSM option would consist of voluntary programs that leverage equipment and load management systems to enable peak load reductions to occur. BC Hydro proposes to pilot capacity-focused programs (direct load control) for residential, commercial and industrial customers over two years, starting in F2015.

Table 9-10 summarizes the UC of capacity-focused DSM.

Table 9-10 Utility Cost of Capacity-Focused DSM ($ million)

	Two years: F2015 to F2016
Industrial Load Curtailment	0.75
Capacity-Focused Programs	5.00
Total	5.75

As described in Chapter 3, capacity-focused DSM represents a new capacity resource to BC Hydro and is subject to uncertainty with respect to its ability to reduce the system peak over the long term.

In general, experience is needed to see how savings for each initiative translates into peak reduction for the entire BC Hydro integrated system. BC Hydro has had experience with load curtailment programs for large industrial customers. To date, these programs have not resulted in a long-term commitment either by BC Hydro to acquire load curtailment, or customers to interrupt or adjust operations when and as required. Other jurisdictions have established practices of relying on long-term load curtailment for peaking capacity and some forms of operational reserve. BC Hydro will consider these jurisdictional practices, taking into account their differences and experiences. For these reasons, BC Hydro will not yet rely on capacity savings from capacity-focused DSM for resource planning purposes, and thus potential capacity-focused DSM savings are not included in the DSM target at this time.

9.2.2.1 Justification

Need: Assuming implementation of the DSM target and EPA renewals, there is a need for capacity resources beginning in F2019 with or without Expected LNG load. BC Hydro proposes to address the short-term peak capacity gap (without LNG load) from F2019 to F2023 with a series of bridging measures such as market purchases and power from the Columbia River Treaty (referred to as the Canadian Entitlement or **CE**). Capacity-focused DSM provides the capacity potential to reduce the need for bridging resources. Implementation will provide BC Hydro with information on the cost and impacts of capacity-focused DSM, which will inform decisions on whether to rely on capacity-focused DSM as a long-term capacity resource.

Cost-Effectiveness: Industrial load curtailment and capacity-focused programs have the potential to deliver cost-effective capacity savings over the long term. Costs would be managed against BC Hydro's capacity LRMC.

Environmental Attributes: Capacity-focused DSM may avoid the need for some of the market bridging mechanisms, resulting in a lower environmental footprint.

Policy Alignment: Capacity-focused DSM would support BC Hydro in meeting the legally binding self-sufficiency requirement (*CEA*, subsection 6(2)).

9.2.2.2 Execution

BC Hydro will design and then launch a voluntary industrial load curtailment offer and capacity-focused programs (direct load control). For load curtailment, BC Hydro envisions the following:

- F2015: BC Hydro will work with industry to explore the level of interest and curtailment opportunity, and to develop conceptual program offers, including contractual terms and conditions
- F2016 – F2017: BC Hydro will test the conceptual offers to understand the industry's response and key integration aspects. BC Hydro will launch the full program offer allowing industry to respond to and be comfortable with the

program. The program can then be expanded (by number of participants or level of participant commitment in hours or MW) based on future BC Hydro need (MW) and value ($/kW-year).

The following steps are anticipated for the direct load control part of capacity-focused DSM programs:

- F2015 – F2016:BC Hydro will implement a voluntary two-year pilot program for residential, commercial and industrial customers in a specific region to test conceptual offers, understand key integration aspects, and design the program offer
- In F2017, BC Hydro will launch the full program

BC Hydro will employ the same risk mitigation tactics as for the DSM target. Refer to section 9.2.1.2.

9.2.2.3 Future Approval Process

BC Hydro will file an expenditure schedule with the BCUC for acceptance of expenditures for F2014 to F2016 pursuant to subsection 44.2(1)(a) of the *UCA*, as part of the DSM expenditure schedule described in section 9.2.1.3 with respect to the DSM target.

9.2.3 Recommended Action 3: Explore more codes and standards

Explore additional opportunities to leverage more codes and standards to achieve conservation savings at a lower cost beyond the current target and to gain knowledge and confidence about their potential to address future or unexpected load growth.

This action has an approximate cost of $1.5 million per year for F2015 and F2016. (There are no F2014 expenditures).

9.2.3.1 Justification

Opportunities to leverage additional levels of DSM-related codes and standards support provides the potential to deliver additional cost-effective electricity savings. However, there is considerable uncertainty regarding the implementation and achievement of these additional electricity savings. This action will investigate and further develop the range of codes and standards tactics to reduce uncertainty about their feasibility and/or savings estimates and ultimately inform subsequent IRPs. By doing so, it is expected that this Recommended Action will support further government work. An example is the Pacific Coast Collaborative's[6] "2012 West Coast Action Plan on Jobs" that among other things seeks to jointly develop energy efficiency standards for appliances such as television set-top boxes, lighting, television, battery chargers, computer/servers and standby losses for a broad range of electronics.

9.2.3.2 Execution

BC Hydro will undertake a range of activities focused on additional codes and standards, including: 1) strategy development; 2) market research, studies and opportunity assessments; 3) measure design, including modeling and cost-benefit analysis; 4) customer, trade ally and/or stakeholder engagement; and 5) pilot programs. BC Hydro will design and manage these activities to achieve the objectives of enhanced certainty at a reasonable cost.

9.2.3.3 Future Approval Process

BC Hydro will file an expenditure schedule with the BCUC for acceptance of expenditures for F2014 to F2016 pursuant to subsection 44.2(1)(a) of the *UCA*, as part of the DSM expenditure schedule described in section 9.2.1.3 with respect to the DSM target.

[6] On June 30, 2008, B.C., Alaska, California, Oregon and Washington State signed the Pacific Coast Collaborative Agreement.

9.2.4 Recommended Action 4: Optimize existing portfolio of IPP resources

Optimize the current portfolio of IPP resources according to the key principle of reducing near-term costs while maintaining cost-effective options for long-term need.

The combined Independent Power Producer (**IPP**) supply and targeted DSM results in BC Hydro having an adequate energy supply until F2028 and adequate capacity supply until F2019, as shown in section 4.2.6. BC Hydro is undertaking time-critical actions over the next few months to prudently manage the costs of the energy resources that it has acquired, committed to or planned to target over the next five years. These actions include negotiating agreements to defer commercial operation date (**COD**), downsize or terminate pre-COD EPAs. Based on the EPA actions, BC Hydro expects to achieve an energy supply reduction of contracted energy by F2021 of roughly 1,800 GWh/year, translating into a reduction in attrition-adjusted forecasted firm energy supply of about 160 GWh/year by F2021.

9.2.4.1 Justification

The energy and capacity LRBs depicted in section 4.4.2.6 after implementation of the DSM target and EPA renewal assumptions show:

- There is an energy gap beginning in F2028 and a capacity gap beginning in F2019 without Expected LNG load
- The corresponding energy and capacity gaps begin in F2022 and F2019, respectively, with Expected LNG load

BC Hydro identified three categories of potential EPA portfolio supply reductions:

1. Pre-COD EPAs where there is some ability to defer COD, downsize capacity or terminate the EPA
2. EPA renewals where contracts are coming to end of life
3. New EPAs

For all three categories, as described in section 4.2.5.1, projects were assessed based on cost, implementation risk, system benefits and economic development benefits.

9.2.4.2 Execution

Termination, Deferral or Downsizing of Pre-COD EPAs: To date, BC Hydro has executed mutual agreements to terminate four EPAs, representing 147 MW in nameplate capacity and 980 GWh in total annual generation (prior to attrition adjustment). BC Hydro is in discussions with IPPs where development of pre-COD EPA projects has stalled, with the objective of obtaining mutual agreement to terminate these contracts.

BC Hydro is continuing to discuss options for deferral or downsizing of EPAs with developers, where feasible options exist.

EPA Renewals: As described in section 4.2.5.1, prior to this IRP BC Hydro assumed that no bioenergy EPAs would be renewed upon expiry due to pricing and fuel supply risks, and that all other EPAs would be renewed for the remainder of the planning horizon. For planning purposes, BC Hydro now assumes that about 50 per cent of the bioenergy EPAs will be renewed, and about 75 per cent of the run-of-river hydroelectric EPAs that are up for renewal in the next five years will be renewed. These EPA renewal planning assumptions would result in about 1,800 GWh/year of firm energy in F2021 and about 6,400 GWh/year of firm energy in F2033.

However, IPP projects will be individually assessed as EPAs come up for renewal. BC Hydro recognizes that EPAs can provide beneficial products such as voltage support, dependable capacity (valued using Revelstoke Unit 6 cost of capacity) and dispatchability. A recent example is BC Hydro's plan to exercise an option to extend the EPA term for the 120 MW McMahon Cogeneration natural gas-fired facility located near Taylor, B.C., provides cost-effective firm energy, dispatchability and capacity support to the local transmission system. Consultation with First Nations would be required where there are physical or operational changes to the projects triggered by the renewal.

By way of illustration, renewing about 2,000 GWh/year by F2021 would cost about $2.5 billion (through to F2033 in as-spent dollars).

New EPAs: BC Hydro is continuing to negotiate in good faith with First Nations and other parties where there are agreements committing BC Hydro to negotiate EPAs. For further actions on new IPPs, see the Clean Energy Strategy Recommended Action 10 in section 9.2.10.2 on SOP and Net Metering.

9.2.4.3 Future Approval Process

BC Hydro anticipates that its management of the IPP EPA portfolio will be informed by the IRP review and approval process and through future RRA processes.

9.2.5 Recommended Action 5: Investigate customer incentive mechanisms

Investigate incentive-based pricing mechanisms over the short-term that could encourage potential new customers and existing industrial and commercial customers looking to establish new operations or expand existing operations in BC Hydro's service area.

9.2.5.1 Justification

Because domestic rates are higher than the price that can be obtained on the spot market, one potential strategy to get higher value for the available energy is to increase domestic demand. This is only worthwhile if the increased load is temporary and there is benefit in the initiative. Initiatives that boost demand over a longer timeframe will increase rates and revenue requirements once the additional electricity supplies are needed.

9.2.5.2 Execution

To date, BC Hydro has focused on identifying potential incremental loads from existing TSR customers, which is currently approximately 300 GWh/year. Going forward, BC Hydro will identify potential new customer loads. Section 4.2.5.4 identifies the various design considerations that would need to be considered.

9.2.5.3 Future Approval Process

The future approval process depends on the implementation mechanism:

- Stand-alone legislation: Precedents include the B.C. *Power for Jobs Development Act*[7] which specifically provided that the BCUC did not have jurisdiction in respect of the 'development power rates' offered by BC Hydro. Under the *Power for Jobs Development Act* an administrator was appointed to determine if there was surplus energy and to review applications from an economic, environmental and societal interest perspective.
- Programs/contracts under section 9 of the *CEA:* Use of this mechanism requires Cabinet regulation
- A tariff to be filed with the BCUC pursuant to sections 58 to 61 of the *UCA*: The BCUC has broad discretion to determine if a rate is just, reasonable, not unduly discriminatory and/or not unduly preferential. A tariff may not permit tailoring for particular customer circumstances.

9.2.6 Recommended Action 6: Continue to advance Site C

Build Site C to add 5,100 GWh/year of annual energy and 1,100 MW of dependable capacity to the system for the earliest in service date of F2024 (for all six generating units) subject to: environmental certification; fulfilling the Crown's duty to consult, and where appropriate, accommodate Aboriginal groups; and Provincial Government approval to proceed with construction.

[7] S.B.C. 1997, c.51.

Site C consists of the development of a proposed third dam and hydroelectric generating station on the Peace River in northeast B.C. Site C would be the third project downstream of BC Hydro's existing generating facilities at GM Shrum (**GMS**) and Peace Canyon and the respective Williston and Dinosaur reservoirs. Site C would be publicly owned and would become one of BC Hydro's Heritage assets.

Site C triggers *B.C. Environmental Assessment Act (**BCEAA**)* and *Canadian Environmental Assessment Act* (***CEAA***).[8] Site C is currently in a harmonized federal-provincial environmental review,[9] which includes a Joint Review Panel (**JRP**) process. The environmental assessment process for Site C started in August 2011 and is anticipated to take approximately three years to complete. Details concerning the harmonized federal-provincial environmental review are provided below.

Site C earliest ISD is F2024 for all six generating units, with the first power from Site C in late F2023. An in service date of F2024 is considered reasonably achievable, subject to environmental certification; fulfilling of the Crown's duty to consult, and where appropriate, accommodate Aboriginal groups; and Provincial Government approval to proceed with construction. BC Hydro has also included a F2026 ISD to provide a basis for evaluation in Chapter 6 of this IRP.

[8] The Executive Director of the EAO issued a section 10 *BCEAA* order on August 2, 2011, determining the Site C is a reviewable project pursuant to Part 4 of the B.C. *Reviewable Projects Regulation*, B.C. Reg. 370/2002; the Agency determined on September 30, 2011 that the requirements to commence an environmental assessment under *CEAA* had been met.

[9] A joint Agreement to Conduct a Cooperative Environmental Assessment, Including the Establishment of a Joint Review Panel, of the Site C Clean Energy Project between the Minister of Environment, Canada and the Minister of Environment, British Columbia was issued on September 30, 2011 after a public comment period, and amended on February 13, 2012.

The final cost estimate for a capital project can only be known after a competitive procurement process is complete and final bids for construction contracts are accepted. Due to engineering, environmental and consultation work done in Stages 2 and 3 (described below in section 9.2.6.1), Site C has reached an advanced level of project definition. The Site C cost estimate of $7.9 billion is commensurate with a Class 3 cost estimate according to the estimating practices of the Association for Advancement of Cost Engineering (**AACE**),[10] as compared to the majority of other IRP resource options that are based on lower accuracy Class 4 or 5 estimates. As described below in section 9.2.6.2, the Site C cost estimate includes adjustments for inflation and the cost of financing during construction, and has undergone both internal and external review.

9.2.6.1 Justification

Need: There is a need for Site C based on the LRB analysis in Chapters 2, 4 and 6 even after taking into account the pursuit of the DSM target set out in Chapter 6. With the implementation of the DSM target and EPA renewals, new resources are required to meet the energy and capacity needs of BC Hydro's customers:

- There is an energy gap beginning in F2028 and a capacity gap beginning in F2019 without Expected LNG load
- The corresponding energy and capacity gaps are F2022 and F2019 respectively with Expected LNG load.

It is difficult to precisely time the addition of any new electricity resource with the exact year of forecasted energy or capacity gaps, particular large hydroelectric facilities such as Site C. There are a number of uncertainties that could result in higher or lower customer demand, and lower or higher resource delivery, including:

[10] As defined in AACE Recommended Practice No. 69R-12, Cost Estimate Classification System – As Applied in Engineering, Procurement and Construction for the Hydropower Industry (revised January 25, 2013), page 9 of 14. The BCUC requires Class 3 cost estimates for CPCN applications; refer to section 5 of the BCUC's 2010 *Certificate of Public Convenience and Necessity Application Guidelines* (BCUC Order No. G-50-10, March 19, 2010).

- **Load Forecast Variability:** BC Hydro's load forecast is sensitive to a number of variables, including economic conditions. Factors that can lead to a lower load than forecast include a reduction in the growth in China and elsewhere, leading to a slowing of commodity demand and lower prices. Factors that can lead to higher than forecast electricity sales include strengthening world demand for commodities and electrification.
- **Expected LNG Load:** BC Hydro has considered an Expected LNG load of 3,000 GWh/year and 360 MW within an overall range of about 800 GWh/year to about 6,600 GWh/year of additional energy demand, corresponding to about 100 MW to 800 MW of additional peak demand
- **DSM Delivery Risk:** The current DSM target is a significant step up from DSM targets BC Hydro pursued prior to the 2008 LTAP. The consequences of DSM not delivering the anticipated capacity savings are of particular concern because while generally external markets can be counted on for supply of energy across the year (albeit with costs), during winter peak periods there are issues with: 1) the illiquid (thinly traded) nature of the market for capacity; 2) insufficient transmission capacity; and 3) the U.S. market potentially not having surplus to sell.

These uncertainties underscore the need to review a range of future resource requirements, rather than solely single-point estimates for LRB energy and capacity gaps.

BC Hydro examined a number of sensitivity cases: 1) large gap (i.e., high load growth with low DSM savings level) and small gap (low load growth with low DSM savings level); 2) high and low market price scenarios; 3) a lower cost of capital assumption for IPP projects; 4) higher capital costs for Site C and some combinations of higher capital costs for resource alternatives; 5) different wind integration costs; and (6) some low probability compound sensitivities. In general, Site C has a Present Value (**PV**) advantage over viable alternative Clean Generation portfolios except in the scenario associated with long-term low load growth, and in the implausible scenario of a 30 per cent capital cost increase for Site C while the cost of alternatives held constant. When compared to the Clean + Thermal Generation portfolio, Site C has a cost disadvantage in the scenarios that are generally low probability associated with long-term low load growth, low market prices and higher Site C capital costs.

BC Hydro considers it prudent to continue to proceed with Site C for its earliest ISD of F2024 given these uncertainties and PV results. Detailed discussion of the timing for the need of Site C to meet load requirements is provided in section 6.4.2.

Cost-Effectiveness: Resources that are viable alternatives to Site C in various combinations are: (1) DSM Option 3; (2) clean or renewable energy e.g., wind, run-of-river, biomass; (3) clean or renewable capacity i.e., Revelstoke Unit 6, GMS Units 1-5 Capacity Increase and pumped storage; and (4) natural gas-fired generation within the *CEA* 93 per cent clean or renewable parameter. All Site C and viable alternative portfolios assumed as a baseline condition achievement of BC Hydro’s DSM target. As demonstrated in section 6.4, Site C is a cost-effective resource.

Site C is a dispatchable resource, and provides ancillary benefits to the BC Hydro integrated system including shaping and firming, and wind integration capability. In contrast, generation from many viable clean or renewable resources such as wind or run-of-river are determined by environmental considerations such as wind speeds or seasonal river flows, and as a result, these intermittent resources cannot be economically dispatched in response to changes in market prices. For example, run-of-river generation generally peaks in the spring and early summer when customer demand is lowest. Facilities such as Site C which are downstream of large hydroelectric storage reservoirs can be operated to have lower generation during the spring and early summer allowing run-of-river generation to be used to serve load as much as possible. Some of these additional benefits are not captured in the PV analysis, further discussion of these additional benefits is provided in section 6.4.5.

Environmental and Economic Development Attributes: The environmental footprint analysis provided no basis to rethink BC Hydro's current actions regarding Site C. The economic development impacts of the Site C portfolio analysis show that portfolios including Site C provide higher amounts of Provincial gross domestic product (**GDP**) and employment. Detailed discussions of environmental and economic development attributes are included in section 6.4.4 and 6.4.5 respectively.

9.2.6.2 Execution

BC Hydro adopted a multi-stage approach for the planning and evaluation of Site C given the long lead time and the scope of evaluation and development work required for a major hydroelectric facility. This approach provides multiple decision-making points during project development, and focuses on specific deliverables and objectives at each stage:

- Stage 1 (Review of Project Feasibility) took place from 2004 to 2007. The review concluded that it would be prudent to continue to investigate Site C as a potential resource option to address the electricity supply gap within BC Hydro's service area.
- BC Hydro moved to Stage 2 (Consultation and Technical Review) following direction by the B.C. Government in the 2007 BC Energy Plan. Stage 2 included consultations with Aboriginal groups, the public and stakeholders, as well as advancing environmental studies, field studies, engineering design and technical work. Based on Stage 2 key findings, BC Hydro recommended proceeding to the next stage of project planning and development, including an environmental and regulatory review.

- BC Hydro entered Stage 3 (Environmental and Regulatory Review) in April 2010, following a decision by the B.C. Government to advance the project to the next stage of development. Stage 3 includes an environmental assessment process by federal and provincial regulatory agencies.
- Should BC Hydro receive environmental certification at the end of Stage 3 for Site C, Stage 4 would include a decision by BC Hydro's Board of Directors and the B.C. Government to proceed to full project construction
- Stage 5 (Construction) is the final stage, involving an approximately seven-year construction period, with one additional year for final project commissioning, site reclamation and demobilization

As part of Stage 3, the Site C project is undergoing a harmonized environmental assessment by lead by the Canadian Environmental Assessment Agency (**Agency**) and the Environment Assessment Office (**EAO**), which includes a Joint Review Panel (**JRP**) process. The environmental assessment process commenced in August 2011 and is anticipated to take approximately three years to complete. The environmental assessment process for Site C includes several public comment periods, as well as public hearings under a JRP.

Milestones of the environmental assessment process for Site C to date include:

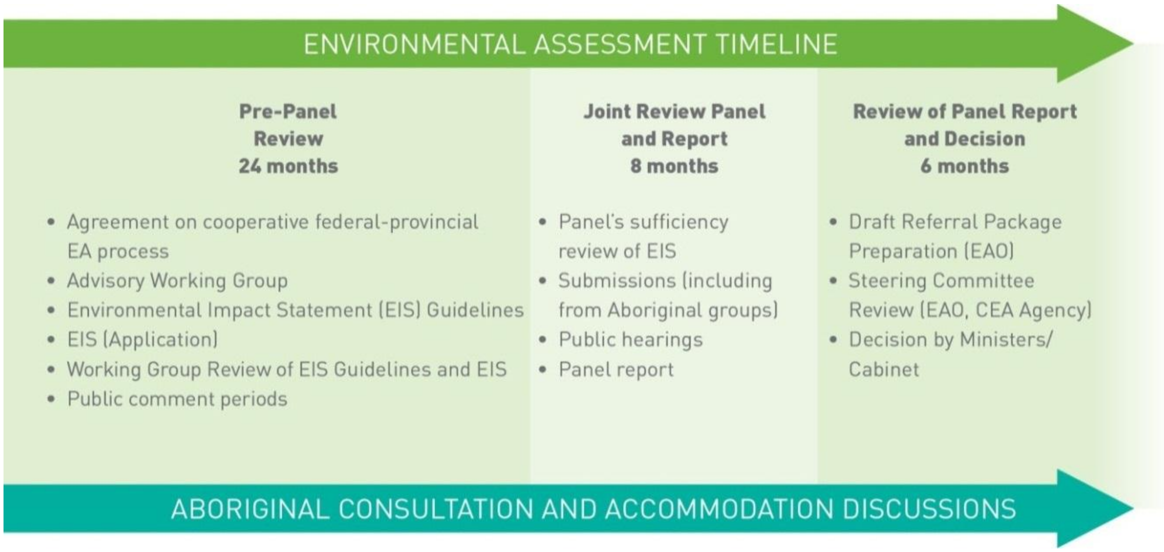
- **May 2011:** BC Hydro initiated the environmental assessment process by submitting a Project Description Report to the Agency and the EAO
- **August 2011:** The Project Description Report was formally accepted by the Agency and EAO, which commenced the formal environmental assessment process
- **September 2011:** A draft agreement was released by the federal and B.C. Ministers of Environment for a harmonized environmental assessment of Site C, including a JRP process. The agreement was subject to a 30-day public comment period.

- **February 2012:** The agreement for a harmonized environmental assessment of Site C was finalized by the regulatory agencies in February (and amended following the implementation of *CEAA 2012*). This agreement provided guidance on expected timing for each review stage.
- **April 2012:** Draft Environment Impact Statement (**EIS**) Guidelines for Site C were issued by the Agency and the EAO for a 45-day public comment period, which included open house sessions in key communities in northern B.C. and Alberta
- **September 2012:** Final EIS Guidelines were provided to BC Hydro by the Agency and the EAO. The EIS Guidelines set out the information that must be included in the EIS for Site C.
- **January 2013:** The Site C EIS was filed with Agency and the EAO. The EIS is a detailed report of potential environmental, economic, social, health and heritage effects of Site C and, where effects cannot be avoided, it identifies options for mitigation. The report also includes a review of the need for Site C and analysis of potential alternatives and benefits of the project.
- **February/March 2013:** The Site C EIS was issued for a 60-day public comment period, which included open house sessions in key communities in northern B.C. and Alberta
- **July 2013:** The Amended EIS, reflecting changes requested by the Agency and EAO, was filed with the Agency and the EAO

August 2013: Commencement of the JRP stage of the environmental assessment.

Figure 9-1 provides a high level summary of the process. Based on the schedule provided by the environmental assessment agencies, the process is expected to be completed in the fall of 2014.

Figure 9-1 Environmental Assessment Process



Risk Mitigation

BC Hydro has reviewed the key project risks and has mitigation strategies in place for each risk identified, as summarized in Table 9-11 below.

Table 9-11 Key Project Risks and Risk Management

Risk: Regulatory Schedule	
Description	**Risk Management**
The regulatory process and schedule for Site C is determined by the federal and provincial regulatory bodies, and may be subject to changes in schedule and/or scope.	Prior to commencing the formal environmental assessment process, BC Hydro undertook project definition work, early environmental studies and other work to determine whether it was prudent to proceed to the environmental assessment stage. This work also included the establishment of several Technical Advisory Committees on key regulatory topics to consult with regulatory bodies and stakeholders regarding the potential scope of required studies. This preparatory work enabled some anticipation of the requirements of the environmental assessment process, and mitigates the risks of a process delay. Site C is now undergoing the formal environmental assessment process. In February 2012, the federal and provincial governments announced that an agreement had been finalized for a harmonized environmental review of Site C. This agreement identified defined timelines associated with the key steps of the environmental assessment process. To date, these defined timelines have been met and the regulatory process is on schedule.

Risk: Achieving Accommodation Agreements with First Nations, where appropriate	
Description	**Risk Management**
The Crown has a duty to consult, and where appropriate, accommodate Aboriginal groups.	BC Hydro and Aboriginal groups are engaged in consultation and engagement processes that will continue through all stages Site C. To date, BC Hydro has engaged approximately 50 Aboriginal groups in B.C., Alberta, Saskatchewan and the Northwest Territories. BC Hydro has concluded 13 consultation agreements representing 16 First Nations to date. Others remain under discussion. Consultation activities include: • Providing access to and facilitating an understanding of project-related information, including but not limited to the need for and alternatives to Site C; • Identifying and understanding the issues, interests and concerns brought forward by Aboriginal groups about Site C; • Creating opportunities to receive input from Aboriginal groups into the planning, design, construction and operation of Site C; • Acquiring, considering and incorporating traditional land use information; • Facilitating participation in the environmental assessment process through provision of capacity funding and access to technical expertise as it relates Site C; • Negotiating IBAs where appropriate; • Identifying potential training, employment, contracting and broader economic opportunities related to the project that may be of interest to Aboriginal groups or individuals.
Risk: Project Design	
Description	**Risk Management**
New technical information could require a change in project design or construction.	BC Hydro undertook significant site investigation work in the design phase of the project. This allowed BC Hydro to characterize ground conditions for design and construction purposes. As a result of these investigations and associated engineering work, the project design has been upgraded from the historical project design to meet current seismic, safety and environmental guidelines. The project design for Site C is robust and capable of meeting unexpected conditions. Key design upgrades have resulted in improved foundation stability, greater seismic protection, enhanced spillway safety and additional generating capacity. In keeping with BC Hydro and international practice for major projects, an external technical advisory board composed of global experts in hydroelectric development reviewed and provided feedback on BC Hydro's design choices for Site C.

Risk: Project Costs	
Description	**Risk Management**
There is the risk of additional costs or delays during the construction phase.	Due to engineering, environmental and consultation work done in Stages 2 and 3, Site C has reached an advanced level of project definition. As a result, the $7.9 billion project cost estimate is at a higher level of accuracy than previous estimates (the Site C cost estimate is a Class 3 cost estimate). BC Hydro is utilizing project management and project control methods to deliver the project within this mandate. The Site C cost estimate includes contingencies (18 per cent on direct construction costs and 10 per cent on indirect costs, excluding some costs in reserves). This an appropriate level of contingency given the level of uncertainty in future conditions. BC Hydro's capital cost estimate for Site C has undergone an external peer review by KPMG, which determined that the methodologies and assumptions used in the cost estimate are appropriate. The project procurement approach has been designed to, among other things, efficiently allocate and manage project risks to reduce the likelihood of construction cost overruns or delays.
Risk: Labour	
Description	**Risk Management**
Availability of labour could be constrained during the construction period.	BC Hydro is working with contractors, employers, educational institutions, local and Aboriginal community groups, employment agencies and related organizations to advance initiatives to secure an available supply of qualified local workers. Some examples of initiatives aimed at providing local labour opportunities include undertaking skilled trades capacity building. Examples of capacity building include providing $1 million to support trades and skills training at Northern Lights College, and other contributions aimed at attracting new entrants into trades training. The Site C cost estimate includes an appropriate level of contingency to reflect uncertainty in future conditions.

9.2.6.3 Future Review Process

Environmental Assessment: As described above, Site C has entered the JRP stage of the harmonized federal-provincial environmental assessment process. A large number of federal, provincial and local government permits and approvals will be required during the construction and operational phases of Site C, including authorization from Fisheries and Oceans Canada pursuant to sections 32 and 35(2) of the Canada *Fisheries Act*.[11]

[11] R.S.C. 1985, c.F-14.

BCUC: BC Hydro is exempt from any requirement to obtain a Certificate of Public Convenience and Necessity (**CPCN**) for Site C pursuant to subsection 7(1)(d) of the *CEA*. BC Hydro anticipates that the costs for Site C would be amortized over a long period. This amortization period and rate impact would be determined through a future regulatory process with the BCUC.

9.2.7 Recommended Action 7: Pursue bridging options for capacity

Fill the short-term gap in peak capacity with cost-effective market purchases first and power from the Columbia River Treaty second.

Site C is expected to be available by F2024. There is a five-year capacity gap with or without Expected LNG load from F2019 to F2023. BC Hydro proposes to rely on the market, backed up by the CE provided under the Columbia River Treaty, for up to about 300 MW to meet any system capacity shortages during this period because the reliance is for a short period and because the market/CE is cost-effective as compared to B.C.-based capacity resources that could be in-service by F2021 and would only be needed for about five years.[12]

However, there is uncertainty with respect to the CE. While the Columbia River Treaty has no termination date, either Canada or the U.S. can unilaterally terminate most of the provisions of the Columbia River Treaty any time after September 16, 2024, providing at least 10 years' notice is given. In addition, planning to rely on the market for the five-year F2019 to F2023 period does not meet the self-sufficiency requirement set out in subsection 6(2) of the *CEA*. Lieutenant Governor-in-Council (**LGIC**) authorization is required.

For Expected LNG load, BC Hydro would advance natural gas-fired SCGTs for the North Coast in a staged and flexible manner as back-up for transmission outages and reliability. Refer to section 9.3.2.

[12] Burrard would continue to be available to provide transmission support services and in the case of emergency as permitted by section 13 of the *CEA*.

9.2.7.1 Justification

Relying upon the markets and the CE as bridging resources for up to about 300 MW for the five-year F2019 to F2023 period is beneficial for BC Hydro's ratepayers. The costs to maintain the market and CE capacity options is lower than the alternative solutions of either building new natural gas-fired generation or Revelstoke Unit 6 solely for a five-year period before Site C's earliest ISD. The market and CE capacity option-related costs are expected to be incidental business expenses.

9.2.7.2 Execution

To ensure BC Hydro has adequate capacity resources available to bridge to Site C, BC Hydro and Powerex will undertake two activities:

- Continue to monitor market conditions and U.S./Alberta transmission system development to facilitate and ensure that BC Hydro has access to up to about 300 MW of market purchases during all hours of the year and with a specific focus on BC Hydro's winter system peak load conditions
- Manage CE, trade commitments and market optimization to about 300 MW of the CE to be available to back up the 300 MW of market purchases

9.2.7.3 Future Approval Process

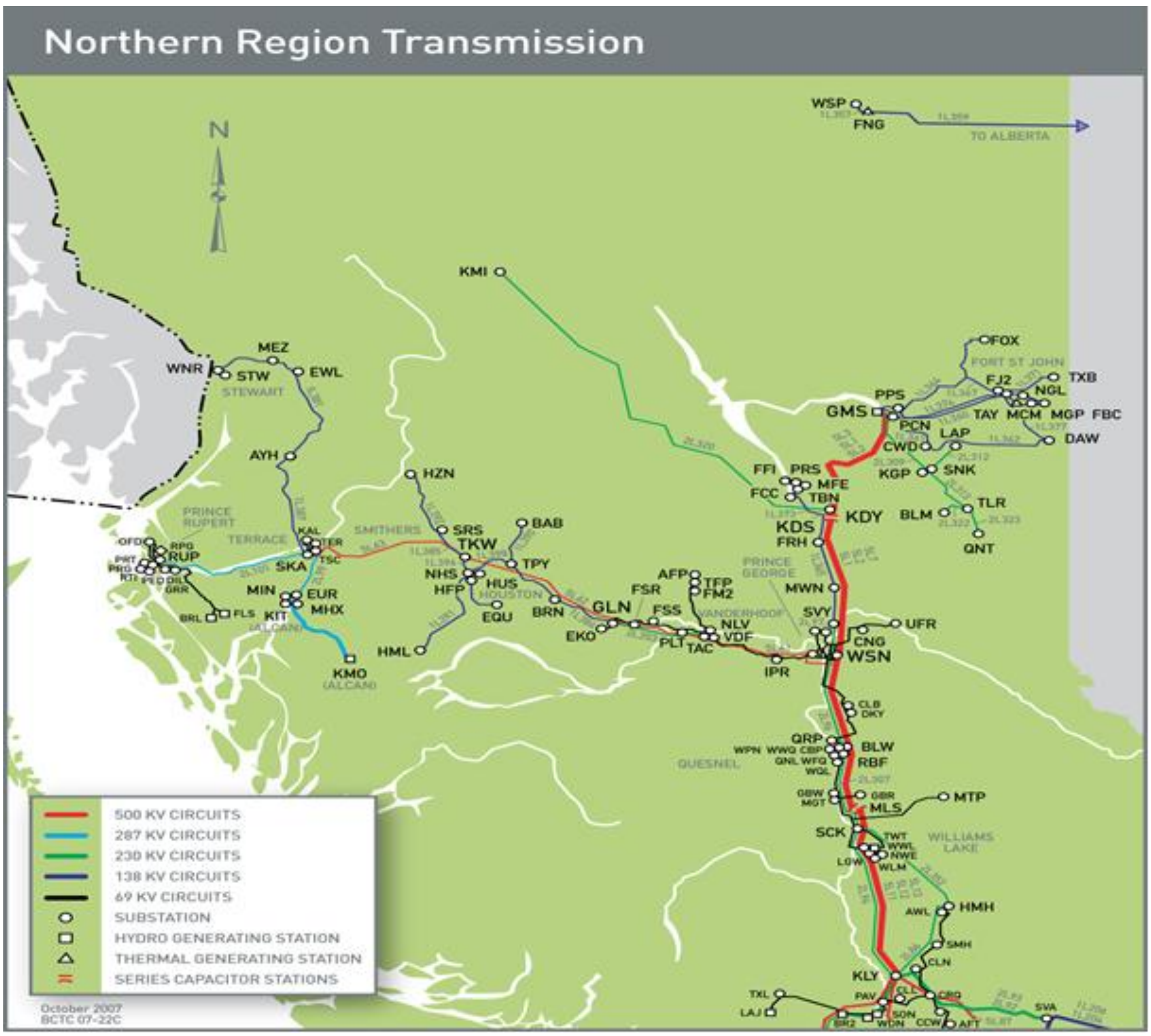
Relying upon the market and CE for short-term capacity needs from F2019 to F2023 does not meet the self-sufficiency requirements in subsection 6(2) of the *CEA*. Subsection 6(3) of the *CEA* provides an exception to the self-sufficiency requirement found in subsection 6(2). The LGIC may by regulation authorize BC Hydro to enter into contracts for purposes of not meeting the self-sufficiency requirement.

9.2.8 Recommend Action 8: Advance reinforcement along existing GMS-WSN-KLY 500 kV transmission

Advance reinforcement of the existing GM Shrum-Williston-Kelly Lake 500 kV transmission lines to be available by F2024.

The northern transmission system transmits power from the GM Shrum (**GMS**) generating facilities in the Peace River region through to Williston (**WSN**) in the Prince George region to connect with the Interior-to-Lower Mainland system at Kelly Lake (**KLY**) near Clinton, B.C. Three parallel 500 kV transmission lines (with five segments – 5L1, 5L2, 5L3, 5L4 and 5L7) deliver power from GMS to WSN and three 500 kV transmission lines (5L11, 5L12 and 5L13) deliver power from WSN to KLY.

Figure 9-2 Northern Region Transmission



The available transfer capabilities (**ATC**) of the GMS-WSN and WSN-KLY transmission line segments (cut-planes) are expected to be exceeded by dispatch of power from the existing and new resources in the Peace River region. To provide adequate incremental transfer capabilities, these cut-planes have to be reinforced.

Non-wire upgrades contemplated include the addition of shunt compensation at WSN and KLY Substations and enhancing the series compensation at Kennedy and McLeese series capacitor stations. The shunt compensation is expected to add 580 MW to 650 MW to the total transfer capability (**TTC**), while the enhance series compensation are expected to add 630 MW to 750 MW to the TTC.

The cost to complete further study work over the next five years is estimated to be $5.0 million. BC Hydro will have a total cost estimate with an accuracy range of +35 per cent/-15 per cent when the study work is completed. The transmission upgrades are planning level estimates and detailed analytical studies are required to finalize scope and cost.

9.2.8.1 Justification

In the various portfolios that were analyzed in Chapter 6 of the IRP, the need to reinforce the GMS-WSN-KLY transmission line was either by non-wire upgrades or additional transmission lines. Portfolios were also analyzed both with and without Site C as a resource. The results indicate that for portfolios without Site C, the ATC of GMS-WSN-KLY transmission cut-planes will be exceeded by F2029 (with Expected LNG load) and by F2032 (without any potential LNG load) due to the need for new generating resources. In portfolios with Site C, the need for the non-wire upgrades advances from F2029 to F2024.

In the majority of cases, the incremental transfer capabilities of the non-wire upgrades is expected to push the need for new transmission lines in the GMS-WSN and WSN-KLY 500 kV corridors beyond the 30-year planning horizon. In a few remaining portfolios these lines will only be needed towards the end of the 30-year planning period. Given that the majority of the analyzed mid gap portfolios did not require a new transmission line on the GMS-WSN-KLY corridor, the non-wire upgrades are being recommended.

9.2.8.2 Execution

BC Hydro would initiate further studies to confirm scope and cost of the required non-wire transmission upgrades on the GMS-WSN and/or WSN-KLY cut-planes for a F2024 ISD.

9.2.8.3 Future Approval Process

Pursuant to BC Hydro's Capital Project Filing Guidelines, BC Hydro would apply for a CPCN from the BCUC pursuant to subsection 46(1) of the *UCA* if the cost of identified projects is greater than $100 million.

9.2.9 Recommended Action 9: Reinforce South Peace transmission

Review alternatives for reinforcing the South Peace Regional Transmission Network to meet expected load.

The recently approved Dawson Creek/Chetwynd Area Transmission (**DCAT**) project will enhance the transmission capacities in the Dawson Creek and Groundbirch sub-regions. Continued load growth in these and other areas encompassing the South Peace region indicate further regional transmission reinforcements are required. BC Hydro must continue to advance its current regional planning activity referred to as the Peace Region Electrical Supply (**PRES**) study[13] to confirm the preferred regional capacity addition alternative following DCAT.

9.2.9.1 Justification

Electricity demand in the South Peace area is growing due to natural gas exploration and development of the Montney shale gas basin. Over the next 10 years, annual load growth in South Peace is expected to be about 10 times that of the rest of BC Hydro's service area. DCAT will increase the N-0 transfer capability to Dawson Creek and Groundbirch areas to 400 MW. The available capacity is expected to diminish as a result of the growing demand in South Peace region. Additional N-0

[13] PRES was formerly referred to as GDAT (GMS to Dawson Creek Area Transmission).

transmission capacity is expected to be required by F2019. As discussed in section 6.2, the South Peace region is an area where the need to build small, redundant gas units along with the need to operate natural gas-fired units is expected to result in transmission being the preferred supply option.

9.2.9.2 Execution

BC Hydro should complete Identification Phase studies to determine the preferred alternative for providing incremental transmission capacity in South Peace region and secure a F2019 in-service date for the identified upgrades. These studies would, among other things, identify and evaluate alternatives, including local natural gas-fired generation. These studies are expected to be completed by the end of F2014 at an estimated cost of $1.2 million. BC Hydro will have a total cost estimate with a +35 per cent /-15 per cent accuracy range when these studies are completed.

9.2.9.3 Future Approval Process

Pursuant to BC Hydro’s Capital Project Filing Guidelines, BC Hydro would apply for a CPCN from the BCUC pursuant to subsection 46(1) of the *UCA* if the cost of identified projects is greater than $100 million.

9.2.10 Recommended Action 10: Supporting Clean Energy Sector

Advance a set of actions that will support a healthy, diverse clean energy sector and promote clean energy opportunities for First Nations’ communities.

This Recommended Action, as described in Chapter 8, Clean Energy Strategy, was developed in response to the request from the Minister and to address stakeholder comments received during the last IRP consultation period.

9.2.10.1 Justification

As described in section 8.3, the Clean Energy Strategy and this Recommended Action address the Minister’s request to do more to support the clean energy sector in B.C and promote clean energy opportunities for First Nations communities, which also advances the following *CEA* objectives:

- Objective 2(c), "to generate at least 93% of the electricity in British Columbia from clean or renewable resources…"
- Objective 2(h) to encourage the switching from one kind of energy source or use to another that decreases greenhouse gas emissions in British Columbia
- Objective 2(i) "to foster the development of First Nation and rural communities through the use and development of clean or renewable resources."

In scoping the Clean Energy Strategy, BC Hydro was guided by its energy and capacity LRBs and by the *CEA* objective 2(f) "to ensure the authority's rates remain amongst the most competitive of rates charged of public utilities in North America."

9.2.10.2 Execution

The Clean Energy Strategy describes implementation of a set of strategic actionsthat will be initiated over the next two fiscal years, including engagement with stakeholders and First Nations on the design and implementation of key components and annual progress reviews with the B.C. Government.

Key features include:

1. Undertake EPAs Renewals
2. As outlined in sections 1.3, 4.2.5.1, and 8.4.1, BC Hydro continues to rely on EPAs renewals as a major resource to meet future customer demand, second only to DSM in terms of energy volume. By F2017, EPA renewals are expected to account for 1,200 GWh/year of energy, and by F2033, about 6,400 GWh/year.

   BC Hydro has offered a SOP for small-scale clean energy projects since 2008 and a Net Metering Program for residential and commercial customers since 2003. BC Hydro recently modified various SOP rules and made changes to the standard SOP EPA to re-affirm the original spirit and intent of the program. For example, on March 26, 2013 BC Hydro amended the SOP rules to: limit the participation of clustered projects that exceed 15 MW; better manage when SOP energy supply comes on-line by maintaining flexibility to extend CODs for projects by up to two years; and extend the wait period for projects with terminated EPAs from three years to five years as a deterrent to opportunistic behaviour with respect to EPA pricing and other terms and conditions. In addition, this increased waiting period will be better aligned with the timing for when new energy resources are required.

The overall SOP annual target for these type of resources will be increased immediately with the approval of the IRP from 50 GWh/year to up to 150 GWh/year to facilitate the development of small-scale community projects. BC Hydro will amend the SOP by removing high-efficiency cogeneration using non-clean fuels from SOP eligibility to enable a greater role for clean energy. In addition, a “micro-SOP” component, in the range of 100 kW to 1 MW, will be introduced within the overall SOP annual target. The new component is envisioned with a streamlined process to reduce development costs

3. Promote First Nations participation in future development in clean energy projects

In implementing this action, BC Hydro will engage First Nations and IPPs on:

- How to introduce new elements to the SOP to encourage First Nations participation.
- How to put greater emphasis on First Nations participation in clean energy projects as the need for the next major call for power emerges.

4. Highlight Energy Acquisition as part of the IRP CRPs

The uncertainty that BC Hydro faces in its plans are shown in the CRPs and BC Hydro will prepare to launch a major acquisition process should the large gap CRP scenario materialize. The IRP and power acquisition processes must be linked to balance align future energy need with supply, while also reducing the adverse impact of market uncertainty on the B.C. clean energy sector. BC Hydro proposes to review the IRP in two years to among other things assess whether new information is observed to warrant an update to the November 2013 IRP on the recommendation of a new energy call.

5. Pursue bilateral agreements

   In furtherance of the CEA energy objectives, BC Hydro will work with the Province to consider cost-effective bilateral procurements with benchmarking practices adhering to competitive processes. Section 8.4.5 provides the details in examples of these IPP bilateral agreements

6. Work with government to advance electrification

   With input from government policy signals on GHG reductions to incent electrification, BC Hydro will focus on advancing electrification with a focus on industrial, transportation and other sectors.

7. Continue to encourage the use of clean or renewable electricity by the LNG industry

   BC Hydro and government continue to have discussions with LNG developers to understand their electricity supply requirements and the benefits of consuming electricity from BC Hydro. BC Hydro is prepared to serve all electricity demands arising from the development of the industry in B.C.

8. Regularly update the inventory of clean or renewable resource options in B.C.

   BC Hydro is committed to maintaining a current understanding of the resource potential, prices and technical capabilities of different clean or renewable technologies in B.C. In F2014, BC Hydro will commence engagement with IPPs and industry experts on resource pricing and updating the Resource Options Report.

9.2.10.3 Future Approval Process

Future resource acquisitions that are identified through the electrification activities are expected to inform future IRPs and will be subject to IRP approvals.

Future resource acquisitions related to LNG supply contracts will be approved through the provincial LNG negotiating and contracting process.

Any bilateral IPP EPAs would be filed with the BCUC for acceptance pursuant to section 71of the *UCA*. Incremental EPAs would be subject to BCUC review of prudency through future RRA processes.

9.2.11 Base Resource Plan LRBs

The Recommended Actions identified in section 9.2.1 through to section 9.2.9 provide BC Hydro's BRP without Expected LNG load for meeting its current and future customers' electricity needs on a reliable and cost-effective basis. The BRP aligns with the *CEA* energy objectives.

The near-term costs associated with the recommended actions to correspond to the BRP Load-Resource Balances are outlined in Table 9-12.

Table 9-12 F2014 to F2016 BRP Recommended Action Execution Expenditure

Recommended Action		Near-Term Execution Expenditure (in $F2013)			
		Applicability	F2014 ($ million)	F2015 ($ million)	F2016 ($ million)
DSM (Conservation)	1. Moderate current spending and maintain long-term target	Program execution	175	145	125
	2. Pursue DSM capacity conservation	Program execution	1.9	1.9	1.9
	3. Explore more codes and standards	Program execution	N/A	1.5	1.5
Portfolio Cost Management	4. Optimize existing portfolio of IPP resources	N/A			
	5. Customer incentive mechanisms	N/A			
Supply-Side Resources	6. Continue to advance Site C	Annual expenditure excluding IDC[14]	88	311	376
	7. Pursue bridging options for capacity	No cost estimate			
Transmission Resources	8. Advance reinforcement along existing GMS-WSN-KLY 500 kV transmission line	Notional expenditures for technical studies	1	1	1
	9. Reinforce South Peace transmission	Notional expenditures for technical studies	1.2	N/A	N/A
	10. Supporting Clean Energy sector	Consultation and Consultant Studies	N/A	1	1

The LRBs for energy and capacity after implementation of the BRP Recommended Actions are depicted in Figure 9-3 and Figure 9-4 respectively.

[14] Project annual expenditures as shown exclude interest during construction (**IDC**), nominal expenditures are converted to F2013 constant dollars based on a 2% annual inflation rate; F2015 and F2016 estimates are reflective of Site C's 10-year plan.

Figure 9-3 Energy LRB for BRP

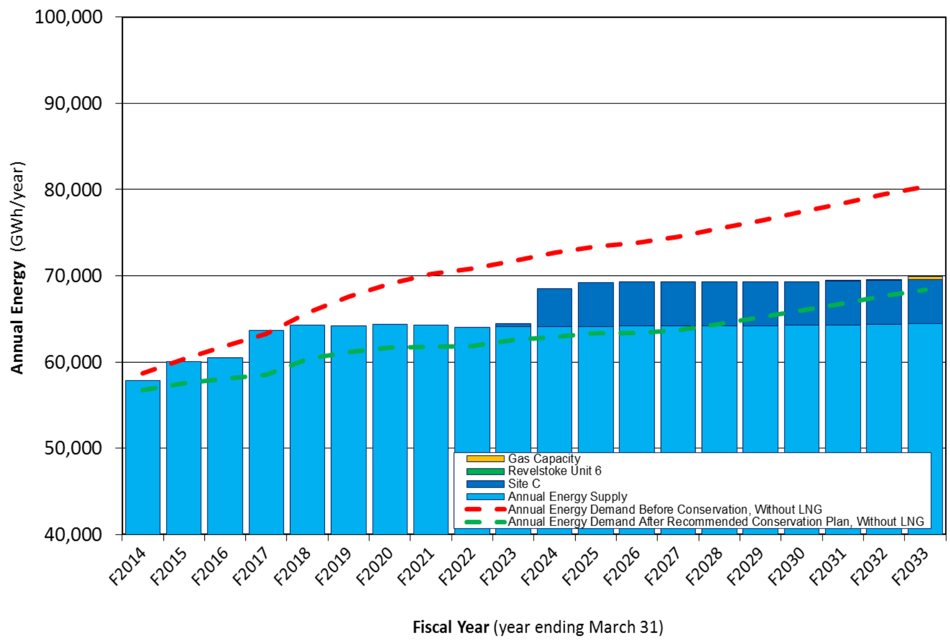
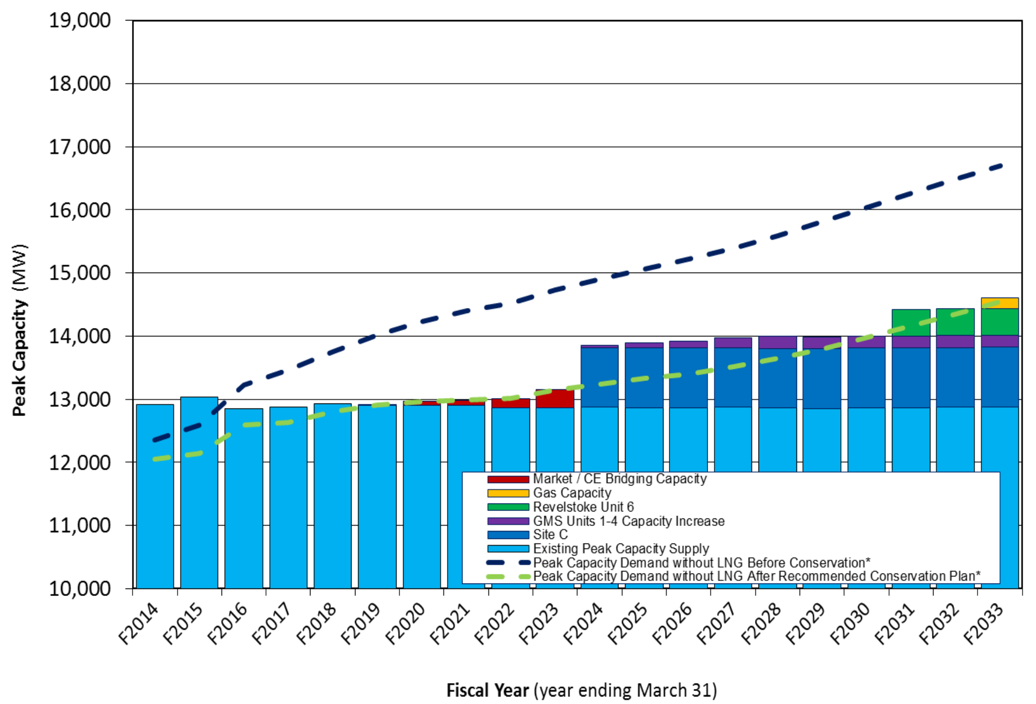


Figure 9-4 Capacity LRB for BRP



* including planning reserve requirements

The BRP shows that the Recommended Actions will supply sufficient energy prior to Expected LNG to meet customers' needs past F2033 for energy; however, additional capacity resources will need to be developed over the later stages of the F2020s. In bridging to Site C, about a 300 MW reliance on market and CE will be required and would be cost-effective.

9.2.12 Long Run Marginal Cost

BC Hydro uses the LRMC to signal the value that should be placed upon acquiring new resources which include: DSM savings; IPP EPA renewals; new IPP acquisitions; Resource Smart; Site C; and equipment efficiency and loss valuations. As the LRMC increases, the available supply from each of the resource types increases. This section highlights the LRMC based upon the BRP that will guide future processes and investments. Supplying the Expected LNG load will not have a material impact on the energy LRMC because BC Hydro has enough energy resources to serve the Expected LNG load with the implementation of the BRP. Expected LNG would not likely materially impact the capacity LRMC because BC Hydro anticipates that the LNG-related need for incremental capacity will be met by SCGTs, leaving Resource Smart projects such as Revelstoke Unit 6 as the marginal capacity resource.

9.2.12.1 Definition

LRMC can be defined as the change in the long-run total cost resulting from a change in the quantity of output produced. In short, LRMC represents the price of the most cost-effective way of satisfying incremental customer demand. The standard economic technique used to determine LRMC is to calculate the minimum present-day view of the cost of meeting a permanent increment (or decrement) of demand in which all capital and operating production inputs can be considered variable. BC Hydro uses an approach where the incremental resource acquisitions needed to supply future requirements are stated on a levelized unit electricity cost basis to aid in comparing resources with differing attributes.

9.2.12.2 Setting the LRMC

Energy

Over the past 10 years, BC Hydro had a significant projected need for new resources and the marginal resource was the acquisition of greenfield clean or renewable IPPs. The LRMC reflected the results of the most recent, broadly-based power acquisition process (e.g., the Clean Power Call results). Using this benchmark, the LRMC based upon greenfield clean or renewable IPPs would currently be $135/MWh (F$2013). Greenfield clean or renewable IPPs were the marginal resource since there were insufficient cost-effective alternative resources available to provide the needed supply for customers. This LRMC provided a price signal for BC Hydro to apply to all other resource options listed above.

Chapter 2 demonstrates there is a need for new B.C.-based resources in F2017 and that is why the energy LRMC is not based on spot market price forecasts. Modifications to the self-sufficiency requirements and a lower load forecast have reduced forecasted need, with the next greenfield IPP clean or renewable energy acquisition not expected within the planning horizon unless LNG needs exceed the 3,000 GWh/year expected amount. BC Hydro currently has sufficient alternative cost-effective B.C.-based resources to meet expected future needs including DSM, IPP EPA renewals, Resource Smart, Site C and equipment efficiency and loss valuations. The question becomes how much of these alternative resources need to be acquired to meet expected demand.

As summarized in section 9.2.11, the BRP LRB includes Site C, DSM Option 2 /DSM Target and the recommended EPA management actions:

- As was shown in section 6.4, Site C is a cost-effective clean or renewable resource and if Site C were not constructed, additional greenfield clean or renewable IPPs would be needed. Site C's adjusted UEC is about $85/MWh. However, Site C is not a marginal resource because Site C is needed.

- BC Hydro tested varying levels of DSM in section 6.3 and demonstrated that DSM Option 2 was more cost-effective than DSM Option 3. Hence, not all DSM is being acquired and it is a marginal resource; e.g., incremental Option 3 DSM programs.
- In addition, the IPP EPA renewals that were analyzed in section 4.2.5.1 were cost-effective and were included in the LRBs. Any EPA renewals above planned assumptions would be marginal resources. As described in section 4.2.5.1, BC Hydro expects to negotiate prices at or close to the spot market price forecast but must consider factors such as energy product attributes and associated non-energy benefits.

Thus, DSM and EPA renewals are marginal resources over the planning horizon (i.e., thru F2033), after which BC Hydro would again require greenfield clean or renewable IPPs. In the process of developing and analyzing the IRP as discussed in Chapters 4 and 6, the LRMC was reduced from $135/MWh to $100/MWh. This reduced value informed the levels of DSM modelled and the upper price limit on EPA renewals. It also informed what Var and Volt Optimization (**VVO**) savings to target as well as provided a price signal for internal equipment acquisition/ loss evaluation decisions. Depending on the amount of LNG load that BC Hydro ultimately serves and whether non-LNG load growth occurs as expected, the LRMC may be reduced to about $85/MWh and still provide an adequate supply of resources over the planning horizon.

Capacity

The LRMC for capacity resources when needed to augment the acquisition of energy and capacity resources is based upon Revelstoke Unit 6, which is lower cost than SCGTs. Revelstoke Unit 6 is being advanced as a contingency resource for its earliest in-service date; however, it is not expected to be needed in the BRP until F2031 . The Unit Capacity Cost (**UCC**) for Revelstoke Unit 6 is between $50/kW-year and $55/kW-year.

Energy and Capacity LRMC Summary

The LRMC outlook is as follows:

- Energy: $85 to $100 per MWh F2017 thru end of the planning horizon (i.e., F2033)
- Capacity: $50 to $55 per kW-year F2017 thru F2032.

The energy and capacity LRMCs relate to the cost of procuring annual firm energy and dependable capacity delivered to the Lower Mainland; hence, adjustments as described in section 3.4.3 and Appendix 3A-34 (such as the costs of transporting the energy and capacity to the Lower Mainland, including line losses) are included in the LRMCs.Energy LRMC Implications:

EPA Management

As described in Chapter 4, BC Hydro's EPA renewal planning assumptions are: a) 75 per cent for small run-of-river project EPAs; b) 50 per cent for bioenergy EPAs; and c) 100 per cent for the remainder of EPAs. This results in about 4,700 GWh/year of firm energy from EPA renewals by F2024. As described in section 9.2.4, BC Hydro should be able to benefit from the fact that the IPP would have fully or largely recovered its initial capital investment in the initial EPA term, by negotiating a lower energy price recognizing that the seller's opportunity cost is selling into the spot market. Section 5.6 of this IRP contains BC Hydro's reference (mid) spot market forecast of Mid-C prices ranging from about $25/MWh to $40/MWh over the next 20 years.

The spot market provides non-firm energy and no capacity, and generally has a term of one hour.[15] EPA renewals provide a different product than the spot market, including a longer contract term and in some cases dependable capacity, voltage

[15] Market forward fixed-price contracts are available for terms of up to five years, with less liquidity in later years.

support and dispatchability. Therefore there is likely to be some pricing up-lift from the spot market. BC Hydro is not likely to renew EPAs with a firm energy price greater than the LRMC.

DSM Plans

The IRP has recommended that the DSM target remain unchanged for F2021 at 7,800 GWh/year and 1,400 MW. The DSM plan that is recommended to achieve that plan is shown in section 9.2.1. Contained within that DSM plan are the three DSM tools (i.e., codes and standards, rates structures and programs), which are influenced by the LRMC:

- The conservation rates utilize a two-tier design of which the trailing step is influenced by the energy LRMC. As BC Hydro moves forward with its plans and rate design applications, the new LRMC will need to be considered.
- Programs are also influenced by the LRMC in that programs with the highest UC can be scaled down with the least long-term effects. As discussed in section 9.2.1, DSM programs will generally be designed in a manner consistent with the LRMC.

Other Resource Decisions

The other areas where BC Hydro will generally apply the LRMC include equipment purchases such as conductor sizing, transformer efficiency design and purchases, transmission voltage selection and VVO.

9.3 LNG Base Resource Plan

9.3.1 Recommended Action 11: Explore natural gas-fired generation for the North Coast

Working with industry, explore natural gas supply options on the North Coast to enhance transmission reliability and to meet expected load.

This Recommended Action would advance work to determine where and how natural gas-fired generation could be built in the North Coast to reduce project lead times and to be able to meet LNG load requirements as required. Acquiring SCGT generation on the North Coast would support system generating capacity needed to supply Expected LNG while supporting the transmission system in terms of enhanced reliability of supply and ability to operate during transmission outages for maintenance purposes.

9.3.1.1 Justification

The Prince George to Terrace Capacitor (**PGTC**) project (described in section 9.3.3) is expected to increase the transmission system to be capable of supplying the entire North Coast demand, including new non-compression LNG load, through the radial series compensated 500 kV transmission line that runs from Prince George to Terrace. The radial nature of the North Coast supply makes it susceptible to forced and planned outages of the 500 kV line. Currently, during an outage of the 500 kV line BC Hydro relies on local generation to supply a portion of the North Coast load in an islanded situation. Incremental load growth in the region is expected to exceed the islanding capability of the existing and committed North Coast supply in F2019.

The addition of SCGTs in the North Coast region would increase the capacity available to carry load in the North Coast through extended contingency and maintenance outages. Based on the incremental capacity requirement of 360 MW for the Expected LNG load starting in F2020, four 100 MW SCGTs may be required. The SCGTs would offset the need to build alternative generation in the system including potentially Revelstoke Unit 6. The use of natural gas-fired generation would increase the emission of GHGs, but is consistent with the British Columbia’s Energy Objectives Regulation. The decision on whether to proceed beyond exploring natural gas supply options to committing to build SCGTs would be pursuant to completion of supply agreements between BC Hydro and LNG proponents.

9.3.1.2 Execution

BC Hydro will conduct technical studies to determine the amount of SCGT capacity and ancillary services needed under various islanded operation scenarios. These studies will identify the technical requirements that will allow SCGT supply of the load during both forced and maintenance outages. Detailed project specifications will need to be completed by F2015 such that a subsequent competitive procurement process can be completed and facilities constructed and in-service by F2020, which coincides with the addition of the North Coast non-compression Expected LNG load. The technical studies are estimated to take one year to complete at an estimated cost of $0.5 million.

Assuming the technical studies confirm the need for natural gas-fired generation to support North Coast reliability levels, BC Hydro will conduct a competitive power procurement process to enter into an agreement with a private developer to provide capacity and associated ancillary services, with BC Hydro able to call for services as required. BC Hydro will continue to work with potential developers to design a cost-effective and fair procurement process that will meet LNG ISDs. The design and execution of the procurement process is expected to take nine to 12 months to complete at an estimated cost of $1 million.

9.3.1.3 Future Approval Process

BC Hydro does not yet need to commit to the type and quantities of natural gas-fired generation required to maintain or enhance North Coast supply reliability. Expenditures for specific future resources will be contained in future RRAs or as part of EPA(s) filed with the BCUC pursuant to section 71 of the *UCA*.

9.3.2 Recommended Action 12: Explore clean or renewable supply options, if LNG demand exceeds available resources

Explore clean or renewable energy supply options and be prepared to advance a procurement process to acquire energy from clean power projects, as required to meet LNG needs that exceed existing and committed supply.

To ensure BC Hydro is prepared to meet both Expected LNG and potentially higher volumes of LNG load, BC Hydro will examine potential clean or renewable energy supplies that may be available both in the North Coast region and more generally in BC Hydro's service area. BC Hydro will also contemplate what processes and timeline it would have to follow to meet LNG proponent load requirements.

9.3.2.1 Justification

As shown in Chapter 2, BC Hydro has included a 3,000 GWh/year and 360 MW of load for Expected LNG. As discussed in Chapter 6, BC Hydro has sufficient energy to be able to supply Expected LNG without acquiring additional clean or renewable energy resources. However, given uncertainty as to potential LNG load and the fact that some LNG proponents have projected they could be in-service by F2020, BC Hydro proposes to advance work on developing energy acquisition processes in a staged manner.

9.3.2.2 Execution

Over the next 12 to 24 months, BC Hydro will continue to monitor LNG proponent supply requirements and associated timing. Initial work on process development will include review of the most recent acquisitions and assessing what additional features may be required to meet LNG needs. Future LNG supply, as per the British Columbia's Energy Objectives Regulation and the need to ensure supplies will continue to make LNG proponents cost-effective, can be a mix of clean or renewable and natural gas-fired generation. Exact supply mix would be determined as part of future customer supply negotiations between BC Hydro, the B.C. Government and LNG proponents.

BC Hydro will not launch a power acquisition process until a clear need has emerged; however, BC Hydro will be prepared to meet LNG supply requests. Anticipated funding to ensure acquisition processes are ready to be launched as required range from $50,000 to $500,000.

9.3.2.3 Future Approval Process

The future approval of LNG-related energy acquisitions will be determined by the supply contacts developed.

9.3.3 Recommended Action 13: Advance reinforcement of the 500 kV transmission line to Terrace

Advance reinforcement of the existing 500 kV transmission line from Prince George to Terrace, which includes development of three new series capacitor stations and improvements in the existing BC Hydro substations to be available by F2020.

The purpose of this project is to increase the transfer capacity of the existing 500 kV transmission circuit between WSN and Skeena (**SKA**). The PGTC part of the reinforcement includes the building of three capacitor stations to be located along existing 500 kV transmission lines 5L61, 5L62 and 5L63 between WSN and SKA and providing voltage support to Glenannan Substation. In addition to PGTC, a new 500/287 kV transformer (three 200 MVA units) at SKA is required.

9.3.3.1 Justification

The transmission PGTC upgrades are expected to increase the ability of the North Coast 500 kV transmission line to serve potential increased demand for electricity in northwest B.C. such as LNG Canada in the Kitimat area and potential mine load along the Northwest Transmission Line (**NTL**) corridor.

9.3.3.2 Execution

The PGTC project is currently in the definition (preliminary design) phase. First Nations consultation and stakeholder engagement is taking place to assist with the selection and acquisition of appropriate sites for the capacitor stations. A detailed project plan will be developed for the implementation phase of the project.

Progression into implementation phase at this point will be dependent on the customer making a positive final investment decision, which is expected to occur by the end of F2015. BC Hydro's estimated expenditures to this point and completion of definition phase work are $2.8 million. The estimated cost of the PGTC project is $125 million with an accuracy of +35 per cent /-15 per cent. Detailed work related to addition of a new transformer at SKA has not yet begun. However, the transformer does not cause any expansion of the substation and is considered a low-risk project with shorter duration than PGTC.

9.3.3.3 Future Approval Process

On March 25, 2013 the B.C. government issued the Transmission Upgrade Exemption Regulation (Ministerial Order No. M073), which exempts BC Hydro from Part 3 of the *UCA* with respect to described transmission facilities, including series capacitor stations and related facilities and equipment and SKA transformer.

BC Hydro is in the process of consulting with First Nations with respect to PGTC.

9.3.4 Recommended Action 14: Explore supply options for Horn River Basin and northeast gas industry

Continue discussions with B.C.'s northeast gas industry and undertake studies to keep open electricity supply options, including transmission connection to the integrated system and local gas-fired generation.

While the pace of expansion in the Horn River Basin (**HRB**) has slowed considerably over the past three to four years due to low gas prices and generally poor economic conditions, it is expected that natural gas prices will eventually recover to where this region will again develop. The emerging LNG industry in B.C.'s northwest may be the driver for further development.

To maintain options to electrify this region to both facilitate development and potentially to manage GHGs that may be emitted, BC Hydro recommends that it continue to: monitor natural gas industry developments; engage with industry to keep open supply alternatives to northeast B.C. and the HRB; and continue to support the B.C. Government in the development of its Climate Action Plan. Options include a transmission connection to the integrated system and local natural gas-fired generation.

9.3.4.1 Justification

In F2013, BC Hydro concluded the Northeast Transmission Line (**NETL**) feasibility study work, which looked at the alternatives for extending electrical service to the natural gas industry in northeast B.C., including transmission connection to the integrated system and local natural gas-fired generation. That analysis, which is summarized in section 6.6 and provided In Appendix 2E), addresses the following questions:

- What actions are required to meet the load in Fort Nelson considering that the solution may be influenced by the HRB industrial loads and supply options?
- What is BC Hydro's strategy to prepare for significant potential load growth in the combined Fort Nelson and HRB region? What actions are prudent in the absence of load certainty?
- What approach should BC Hydro take to support provincial energy objectives on reducing GHG emissions via enabling electrification? This analysis considers the amount of carbon dioxide (**CO_2**) that is produced in the HRB under various natural gas production and energy supply scenarios as well as reduction opportunities.

Although the analysis shows various outcomes depending on market and pricing scenarios considered, the high-level findings are as follows:

- A combination of NETL and system clean or renewable energy strategy can reduce GHG emission by 30 to 38 per cent relative to industry business-as-usual (i.e., self-supply). However, this strategy is generally relatively more expensive than other strategies.
- Natural gas-fired generation strategies can reduce GHG emissions by zero to 16 per cent relative to industry self-supply, but generally do not meet the

93 per cent *CEA* clean or renewable energy objective. Of the natural gas-fired generation strategies, cogeneration appears to be the lowest cost option, but requires a good long-term balance and consistency of heat load and electric load as well as adequate addressing of commercial risks. BC Hydro-acquired cogeneration shifts more GHG emissions to BC Hydro.

The analysis results in the following conclusions:

- First and foremost, the HRB has significant, but uncertain electrification potential. Absent load certainty, all supply alternatives expose BC Hydro to different types and levels of stranded investment risk.
- There remains significant uncertainty with respect to natural gas industry's commitment to take electricity service
- Liability for vented CO_2 needs to be addressed; its inclusion and ownership will heavily influence both the scale of HRB development and the type of work supply alternative that would be most economic. With 70 per cent of total GHG emissions consisting of formation CO_2, meaningful emissions reductions will require carbon capture and sequestration (**CCS**).
- Lastly, in the absence of load certainty or having customers willing to fund the work, it is premature to undertake significant supply actions in the near term to address the potential for large-scale electrification in the region

Given the potential GHG impacts and the *CEA* GHG-related objectives, BC Hydro continues to work with industry on identification of potential future infrastructure requirements and opportunities for minimizing the overall future development footprint for the northeast region.

9.3.4.2 Execution

In line with the recommendation, BC Hydro is continuing to observe and monitor increased interest in electricity supply among natural gas producers operating in the northwest portion of the Montney Basin, i.e., Peace River region north of GMS. This region continues to experience increased levels of activity due to the characteristics of the gas resource and proximity to existing infrastructure. By comparison with the HRB, the Montney Basin resource generally has better economics, is richer in natural gas liquids (in the current price environment proceeds from sales of liquids help improve production returns) and has a lower CO_2 content. This region also encompasses the southern portion of the assumed NETL routing. BC Hydro will be working with Montney Basin natural gas producers and other potential load customers to assess whether there is sufficient electrification potential to justify the need for a Phase 1 (southern portion) NETL project.

Resource requirements for these activities and other analysis will be primarily for external consulting support at an estimated cost of $50,000 to $100,000 over the next three years.

9.3.4.3 Future Approval Process

No material regulatory approval processes are envisioned at this time given the scope of the Recommended Action.

9.3.5 LNG Base Resource Plan LRBs

The Recommended Actions identified in sections 9.3.1 through 9.3.4 provide BC Hydro's LNG BRP to supply Expected LNG load. They are aligned with the *CEA* energy objectives and support the government's LNG strategy and the development of the LNG industry.

The near-term costs associated with the recommended actions to correspond to the LNG BRP Load-Resource Balance are outlined in Table 9-13.

Table 9-13 F2014 to F2016 LNG BRP Recommended Action Execution Expenditure

Recommended Action		Near Term Execution Expenditure (in $F2013)			
		Applicability	F2014 ($ million)	F2015 ($ million)	F2016 ($ million)
Supply-Side Resources	11. Explore natural gas-fired generation for the North Coast	Technical studies	N/A	0.5	N/A
		To design and execute procurement process	1		
	12. Explore clean energy supply options, if LNG demand exceeds available resources	Expected funding for acquisition process	Up to 0.25	Up to 0.25	N/A
Transmission Resources	13. Advance reinforcement of the transmission line to Terrace	To complete Project Definition Phase	1.4	1.4	N/A
	14. Explore supply options for Horn River Basin and northeast gas industry	To monitor load growth in region	Up to 0.1		

The LRBs for energy and capacity after implementation of the LNG BRP Recommended Actions are depicted in Figure 9-5 and Figure 9-6 respectively.

Figure 9-5 Energy LRB for LNG BRP

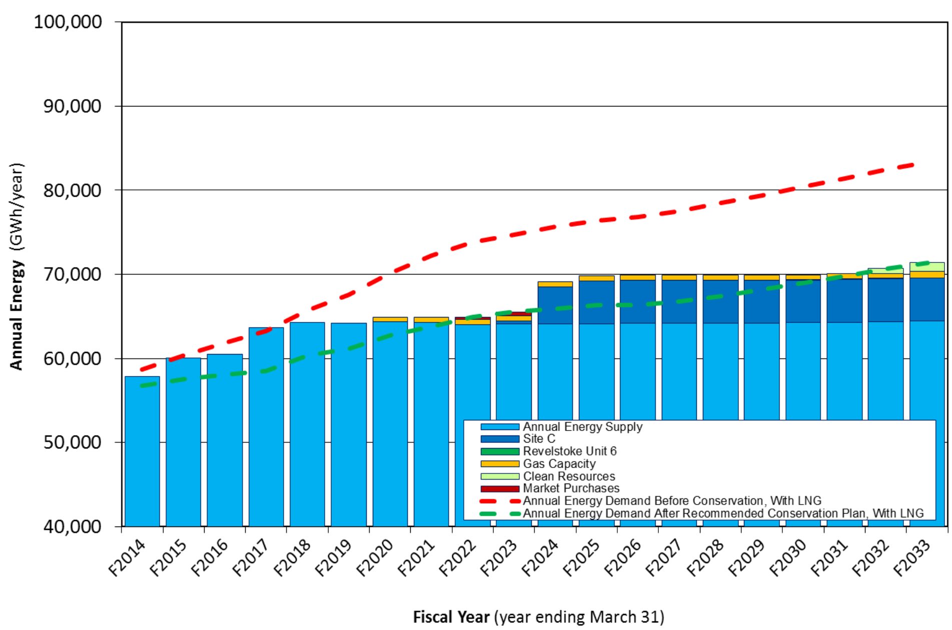
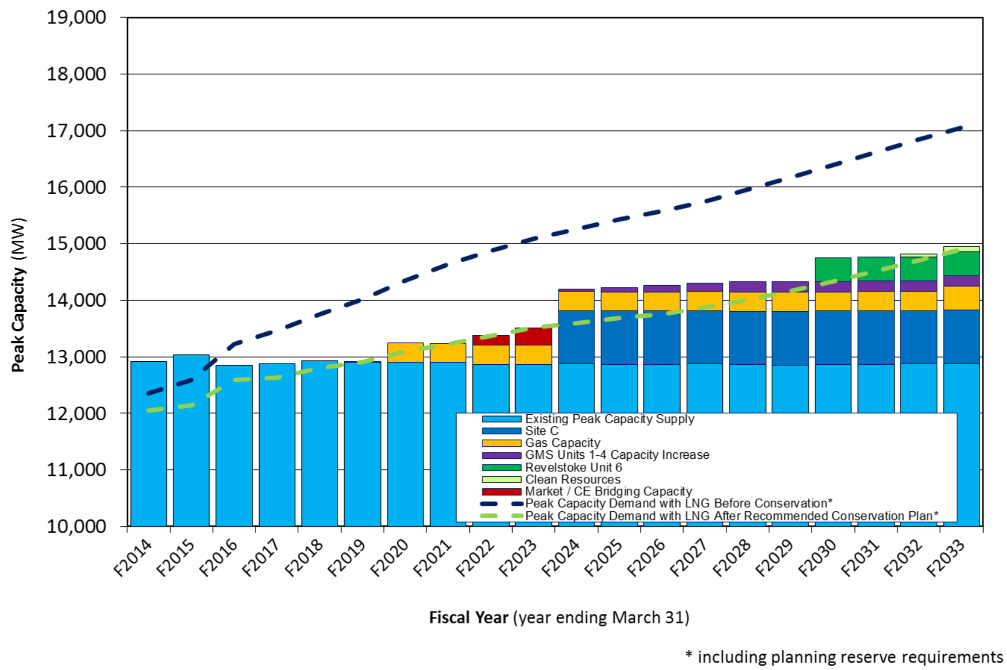


Figure 9-6 Capacity LRB for LNG BRP



The LNG BRP shows that the Recommended Actions will supply sufficient energy to supply Expected LNG needs through F2031, but additional LNG load would advance the need for energy resources. In particular, there are short-term needs prior to Site C that can be bridged with market/CE resources, but additional LNG load would drive the need for more energy acquisitions in the next 10 years. On the capacity side, the BRP shows a reliance of up to about 300 MW from the market backed by CE. In the LNG BRP, the capacity shortfall increases to about 650 MW and exceeds the degree to which market reliance is acceptable. The additional resources to supply the incremental capacity need is expected to be about 400 MW of local natural gas-fired generation which has an ability to support the regional transmission requirements. Towards the end of the F2020's, the need for new capacity is expected to drive the GMS and Revelstoke Unit 6 capacity additions.

9.4 Contingency Resource Plans

9.4.1 Contingency Planning

Contingency planning is done as a reliability management tool to manage the risk (probability and consequence) of not being able to meet load by identifying alternative sources of supply that should be available should the BRP not materialize as expected. Contingency planning is part of good utility practice, and is a component of long-term resource planning recognized as important in the BCUC Resource Planning Guidelines.

As discussed in section 6.9.4.1, the key uncertainties that should be considered in developing contingency plans are load forecast uncertainty, DSM deliverability risk, and effective load carrying capability (**ELCC**) of clean or renewable intermittent resources. However, as concluded in section 6.9.4.3, the range of uncertainty captured by load forecast and DSM delivery uncertainties is considered sufficient to cover the ELCC uncertainty for the purpose of contingency planning. Generation and transmission capacity requirements are the primary concern since capacity is required to meet peak load requirements and maintain system security and reliability.

The process of creating CRPs involves the consideration of the risk that BC Hydro would have an insufficient supply planned to meet its customers' needs and then resolves how to meet those needs. This is done through the creation of alternative portfolios of resources to meet the greater needs.

The aim of CRPs is not to build the required resources in the portfolios but to reduce the lead time for supply-side resources and the required transmission to be placed in- service if a need for them need arises. To minimize the costs of contingency plan actions, BC Hydro seeks to maintain ISDs by moving resources through the identification and definition phases of project development, incurring minimal costs and without committing to construction. If at some point lead time is insufficient to maintain the contingency resource and there is either a sufficiently high likelihood the resource would be required or there is a high consequence of a supply shortage, BC Hydro would secure regulatory approvals (BCUC and/or environmental-related), as required, for its plan to construct the contingency resource initiating final implementation.

BC Hydro submits CRPs to the BCUC for approval pursuant to the OATT and for the purposes of establishing a queue position for a transmission service request. The detailed BRP and CRP tables and graphs that would be the basis of the OATT submission provided to transmission planning are shown in Appendix 8A. CRPs are particularly important in light of the typically long lead times for transmission projects. The CRPs submitted to the BCUC must consider scenarios that reasonably test the transmission pathways that occur based on the possibility of resources and loads in specific locations. Without transmission planning formally including the CRPs in its planning processes and ensuring the associated transmission requirements are being maintained, BC Hydro's CRPs would be ineffectual.

As set out above, BC Hydro developed two CRPs: CRP1 addresses contingencies without Expected LNG load, and CRP2 addresses contingencies with Expected LNG load.

BC Hydro undertakes CRP planning separately for Fort Nelson given that it is not interconnected to the integrated system. The Fort Nelson resource requirements and transmission supply are unique and separate requirements. The Recommended Action related to the Fort Nelson CRP is shown in section 9.4.6.

The load forecast uncertainty (prior to LNG load) and DSM delivery uncertainty that are addressed by both CRP1 and 2 are as shown in Table 9-14.

Table 9-14 CRP Energy and Capacity Shortfalls

Uncertainty	Rationale	Capacity Shortfall[16,17] (MW)		Energy Shortfall (GWh/year)	
		F2017	F2033	F2017	F2033
General Load Forecast Uncertainty	Peak load and energy requirements can increase as a result of sustained growth and/or low temperatures at winter peak.	700	1,550	5,350	10,050
DSM Deliverability Uncertainty	The DSM target has a significant range of deliverability uncertainty where the variability is driven by implementation of codes and standards, customer response to programs and rates.	100	500	550	2,600
Total Reduction		800	2,050	5,900	12,650

The portfolios that were created for CRP1 and CRP2 are shown in sections 9.4.5 and 9.4.6, respectively.

The resulting actions of the two CRPs in terms of analysis for additional transmission requirements will be undertaken when the CRPs are approved by the BCUC and included in the network transmission plan. The generation-related actions driven by both CRPs are advancing Revelstoke Unit 6, GMS Units 1-5 Capacity Increase and natural gas-fired generation.

9.4.2 Recommended Action 15: Advance Revelstoke Unit 6 Resource Smart project

Advance the Revelstoke Generating Station Unit 6 Resource Smart project to preserve its earliest in-service date of F2021 with the potential to add up to 500 MW of peak capacity.

[16] Section 6.9 discusses the ability of intermittent clean or renewable resources to impact the need for new capacity resources and concludes that they are only able to offset the need minimally.

[17] Deliverability risk around DSM capacity savings has been factored into the CRPs. This was performed by examining high, medium and low capacity factor scenarios for the residential, commercial and industrial sectors. Refer to Appendix 4B for a further description.

With Expected LNG, BC Hydro would have up to a 650 MW capacity shortfall over the five-year period (F2019 to F2023) prior to Site C's earliest ISD. Given the *CEA* self-sufficiency requirement and the uncertainty in load and DSM deliverability, BC Hydro proposes to advance Revelstoke Unit 6 through definition phase activity incurring limited costs. Any commitment to construct Revelstoke Unit 6 would be informed by the following: (1) the outcome of the Site C environmental assessment review; (2) LNG proponent final investment decisions; (3) the assessment of the role of natural gas-fired generation for LNG reliability requirements; (4) any future unexpected peak load growth; and (5) any unanticipated reductions in DSM deliveries.

Revelstoke Unit 6 would add 488 MW of long-term (50+ years) dependable capacity to the BC Hydro system, while also providing operational and ancillary services including system shaping, operating reserves, load following and rotational energy required to support intermittent resources. The direct capital cost of Revelstoke Unit 6, in May 2012 constant dollars, is $340 million ($420 million loaded). BC Hydro will spend up to $7.2 million from F2014 to F2016 to ensure Revelstoke Unit 6 is available for its earliest ISD.

9.4.2.1 Justification

BC Hydro has two low-cost, clean or renewable capacity options – Revelstoke Unit 6 and GMS Units 1-5 Capacity Increase:

Table 9-15 Clean or Renewable Capacity Options

Option	MW	ISD	UCC
Revelstoke Unit 6	488	F2021	$50/kW-year
GMS Units 1-5 Capacity Increase	220	F2021-F2025 (one unit per year)	$35/kW-year

BC Hydro proposes to advance both Revelstoke Unit 6 and GMS Units 1-5 Capacity Increase as CRP resources and decide at a later date which should be built first as the most cost-effective capacity option.

Cost Effectiveness: Revelstoke Unit 6 and GMS Units 1-5 Capacity Increase are the two lowest cost capacity options. The cost comparison of all available capacity resources is discussed in section 6.9.

Environmental Attributes: Revelstoke Unit 6 installation work will be contained within the existing footprint of Revelstoke Generating Station (**Revelstoke GS**), and therefore is expected to have minimal additional environmental impact.

Policy Alignment: Revelstoke Unit 6 does not emit GHGs, supports the *CEA* 93 per cent clean energy objective and meets the legislated self-sufficiency requirement in subsection 6(2) of the *CEA*.

9.4.2.2 Execution

Revelstoke Unit 6 is currently in the identification phase with low development uncertainty and medium cost uncertainty of +50 per cent/-15 per cent. BC Hydro proposes to advance Revelstoke Unit 6 through definition phase using a staged and flexible approach in order to limit costs. Cost mitigation activities include:

- Complete the process to obtain environmental approvals, including obtaining an Environmental Assessment Certificate (**EAC**) under *BCEAA* and a water licence to increase the maximum diversion rate by 3,000 cubic feet per second, and related environmental studies
- Consultation with affected First Nations and stakeholders
- Undertaking preliminary design of the project and associated transmission requirements
- Updating assessments of the benefits associated with Revelstoke Unit 6
- Initiation of a staged procurement process targeted for September 2014 with the issuance of a Request for Statements of Qualifications

Business risks include the *BCEAA* review of Revelstoke Unit 6, stakeholder engagement and First Nations consultation. Scope risk is limited since Revelstoke

Unit 6 is fairly well defined, is similar to Revelstoke Unit 5 that went into service in December 2010 and is to be located at the existing Revelstoke GS. A capacitor station is required on the 500 kV transmission line (5L98) between Vaseux Lake Terminal Station and Nicola Substation to increase the capacity of the transmission system in the B.C interior. While the capacitor station will serve all existing generation in the southern interior of B.C., Revelstoke Unit 6 would advance the need for the capacitor station by about 15 to 20 years under current planning assumptions.

9.4.2.3 Future Approval Process

Pursuant to subsection 7(1)(c) of the *CEA*, BC Hydro is exempted from the CPCN requirements of sections 45 to 47 of the *UCA*. On April 11, 2013, the EAO determined that BC Hydro requires an EAC under *BCEAA*. Revelstoke Unit 6 does not trigger *CEAA* because the Regulations Designating Physical Activities[18] provide that the trigger for expansions to a hydroelectric generating station is that the expansion would result in an increase in installed production capacity of: (1) 50 per cent or more; and (2) 200 MW or more. Revelstoke Unit 6 does not result in an increase of the installed capacity of Revelstoke GS of 50 per cent or more. The installed capacity of the existing Revelstoke GS with the installation of Revelstoke Unit 5 is about 2,480 MW.

9.4.3 Recommended Action 16: Advance GM Shrum Resource Smart Project

Advance Resource Smart upgrades GM Shrum Generating Station Units 1-5 with the potential to gradually add up to 220 MW of peak capacity starting in F2021.

As part of its continuous review of opportunities to cost-effectively upgrade existing hydroelectric generation stations, BC Hydro identified a potentially low cost capacity

[18] SOR/2012-147, section 3(b).

opportunity at GMS, a capacity increase of Units 1-5. GMS Units 1-5 Capacity Increase could provide about 220 MW of dependable capacity (about 44 MW per unit). GMS is located next to the W.A.C. Bennett Dam on the Peace River. GMS is one of BC Hydro's largest capacity generating stations (about 2,790 MW) and one of the most important components of the integrated system. The GMS Units 1-5 Capacity Increase conceptual-level cost estimate (loaded) is about $104 million. F2015-F2016 capital spending on GMS Units 1-5 Capacity Increase is forecasted to be between $700,000 to $800,000 to determine feasibility and other related identification phase activities.

9.4.3.1 Justification

GMS Units 1-5 Capacity Increase potentially may have a lower UCC than Revelstoke Unit 6:

- The UCC for GMS Units 1-5 Capacity Increase is estimated to be about $35/kW-year. This is based on a conceptual-level cost estimate with a range of accuracy (+100 per cent/ -35 per cent).
- Revelstoke Unit 6 has a UCC of about $50/kW-year

BC Hydro must balance the timing for the need for dependable capacity, costs, the difficult scheduling and coordination issues if it were to implement GMS Units 1-5 Capacity Increase:

- There is extensive work underway and planned at GMS involving 11 different projects[19] on all 10 generating units which impacts when BC Hydro could undertake GMS Units 1-5 Capacity Increase. It is not recommended from a construction coordination, resourcing and safety perspective to implement an additional Units 1-5 capacity increase project while this current capital work is underway inside of this operating facility. These projects are expected to complete around F2020.
- GMS Units 1-5 Capacity Increase could not realistically be started until the 11 GMS projects are largely concluded. The high volume of work and overlap of projects at GMS pose an elevated safety and reliability risk in this operating facility. This is a risk that is being managed through proper co-ordination of the work.

If the GMS capacity increase opportunity is pursued in the future, the earliest the additional capacity would be available is beginning in F2021 with the first unit installation and be complete in F2025 with the last unit installation. During the installation B.C. Hydro would need to consider how unit outages would impact existing peak supply at GMS. These considerations have been reflected in the LRBs in Chapter 9.

[19] The eleven projects are: (1) GMS Unit Transformer Replacement Phase 3 Replacement of Unit 4 13.8 kV to 500 kV step-up transformers; (2) GMS Units 1 to 5 Turbine Replacement - this project includes new turbine runners, wicket gates, wicket gate operating mechanisms, head covers and overhauling remaining turbine components; (3) GMS Station Service Rehabilitation Generating station service providing power for plant controls, fire systems and all auxiliary system; (4) GMS Units 6 to 8 Capacity Increase Replacement of the iso-phase bus and unit circuit breaker on Units 6 to 8 to increase GMS capacity by 90 MW (30 MW per unit); (5) GMS Units 1 to 4 Rotor Pole Rehabilitation of original (1968) rotor winding; (6) GMS Fire Alarm System Replacement of system in this underground generating station; (7) GMS Fire Protection Piping Replacement; (8) GMS Generator Monitoring System Installation Monitoring system to reduce the risk of turbine or generator failures by providing advanced warning. This project includes vibration monitoring (Units 6 to 10), shear pin monitoring (Units 6 to 10), rotor to stator air gap monitoring (Units 5 to 10) and on-line partial discharge activity monitoring (Units 1 to 10); (9) GMS Unit 7 and 8 Exciter Transformer Replacement - Replace the exciter transformers with transformers of a modified design; (10) GMS Units 6 to 10 Governor Control Replacement - Replace the governor controls with a modern, standardized control system; and (11) GMS Units 1 to 10 Control System Upgrade - Replace controls, alarms, and metering to provide automation and significantly enhanced troubleshooting capability.

9.4.3.2 Execution

BC Hydro will continue to review both Revelstoke Unit 6 and GMS Units 1-5 Capacity Increase. BC Hydro proposes to advance GMS Units 1-5 Capacity Increase through identification and definition phase activity using a staged and flexible approach to incur minimal costs. A schedule for GMS Units 1-5 Capacity Increase project could be as follows:

- Identification phase: one-year minimum
- Definition phase: two-and-a-half-year minimum: GMS Units 1-5 Capacity Increase likely triggers *BCEAA*, and BC Hydro would apply for a CPCN from the BCUC. A new water license may be required due to the current diversion limit at GMS, and an addendum to Peace River Water Use Plan may be required.
- Implementation phase: approximately five years, with one unit being placed in service each year
- If the project was initiated in F2016, GMS Units 1-5 Capacity Increase construction would be timed to begin with the completion of the current projects and could be fully in-service by F2025

9.4.3.3 Future Approval Process

Pursuant to BC Hydro's Capital Project Filing Guidelines, BC Hydro would apply for a CPCN from the BCUC pursuant to subsection 46(1) of the *UCA* if project cost is greater than $100 million. BC Hydro may require an EAC pursuant to *BCEAA* as the threshold for modifications to an existing hydroelectric facility is an increase in the nameplate capacity of 50 MW or greater.[20] However, BC Hydro received a section 10(1)(b) *BCEAA* determination that no EAC was required for GMS Units 6-8 Capacity Increase Project, which has a scope similar to GMS Capacity Increase. An

[20] Table 7, Column 1 of the B.C. Reviewable Projects Regulation, B.C. Reg. 370/2002.

additional water license may be required. GMS Units 1-5 Capacity Increase does not trigger *CEAA* because the *Regulations Designating Physical Activities* provide that the trigger for expansions to a hydroelectric generating station is that the expansion would result in an increase in production capacity of: (1) 50 per cent or more; and (2) 200 MW or more. GMS Units 1-5 Capacity Increase does not result in an increase of the production capacity of GMS of 50 per cent or more. The production capacity of the existing GMS is 2,790 MW.

9.4.4 Recommended Action 17: Investigate natural gas-fired generation for capacity

Working with industry, explore natural gas supply options to reduce their potential lead time to in-service and to develop an understanding of where and how to site such resources, should they be needed.

This Recommended Action entails undertaking work to develop natural gas-fired contingency options that focus on reducing the lead time to ISDs and an understanding of where and how to site natural gas-fired generation in the province. Working with IPPs, this will involve identifying and exploring specific natural gas-fired capacity options and procurement processes, should they be needed.

9.4.4.1 Justification

Natural gas-fired generation is the default incremental capacity resource when no other cost-effective capacity resources are available. Refer to section 6.9.

9.4.4.2 Execution

BC Hydro will explore and develop a shelf-ready competitive procurement process to select new natural gas-fired generation projects in B.C. This work will occur in advance of any commercial commitments and BC Hydro will focus activities on the analysis and resolution of key development risks, and commercial and process issues, to develop a credible procurement framework that could be quickly activated if loads occur. BC Hydro will review other North American jurisdictions where natural gas-fired capacity procurements have occurred in the last five years. The potential procurement process is targeted to be completed in F2014 to ensure this option to serve future loads, if they occur.

Some of the key considerations for analysis and design of the potential procurement will be: First Nations engagement and consultation; siting; access to fuel; optimal allocation risks; desired operational characteristics; required project viability; developer strength; ensuring cost-effective pricing; treatment of associated energy; necessary lead times; and potential transmission investments.

Given that little to no greenfield natural gas-fired generation project development work has occurred in B.C. for the last 10 years, there are significant components in siting and development of such facilities that need to be scoped. Depending on the required lead times, BC Hydro may need to initiate procurement in F2015 to maintain new natural gas-fired generation projects as a credible option. This could involve BC Hydro developing and implementing a competitive process to enter into an agreement with one or more developers to evaluate feasibility, undertake various studies (such as geotechnical or environmental), undertake feasibility-level design and engineering work and develop a schedule and budget for the development of potential specific gas projects. Given that the work may occur in advance of any load commitments, BC Hydro will be looking to sharing some of the cost of the work.

The risks for this Recommended Action are:

- The contingency capacity option is not maintained and BC Hydro is unable to meet future load. To ensure that these resource options are available, BC Hydro is committing adequate funds and effort to advance the plans/options. BC Hydro will engage IPPs early in the process to ensure realistic options are being developed.
- BC Hydro incurs significant costs to advance these options and they are not required. To minimize the cost risk, BC Hydro will seek to find a way to risk share with IPPs to develop the resources to a shelf-ready status and avoid committing to major expenditures prior to need being confirmed. BC Hydro

would also implement clear commercial terms that provide a framework for BC Hydro to defer or discontinue further activities with proponents and projects if new emerging loads are deferred or do not proceed. Committing in advance to project development regardless of viability, price or other terms is not in the interest of ratepayers.

9.4.4.3 Future Approval Process

No approvals are required to explore natural gas-fired generation options and siting. If BC Hydro enters into any EPAs, the contracts would be filed with the BCUC under section 71 of the *UCA*. Individual natural gas-fired generation projects will likely trigger *BCEAA* as the threshold is a nameplate capacity of 50 MW or greater,[21] and will require air emission permits pursuant to the B.C. *Environmental Management Act*.[22]

9.4.5 CRP1

CRP1 results in the portfolio shown in Figure 9-7 and Figure 9-8.

[21] *Ibid.* Table 7, Column 2.
[22] S.B.C. 2003, c.53.

Figure 9-7 Energy LRB for CRP1

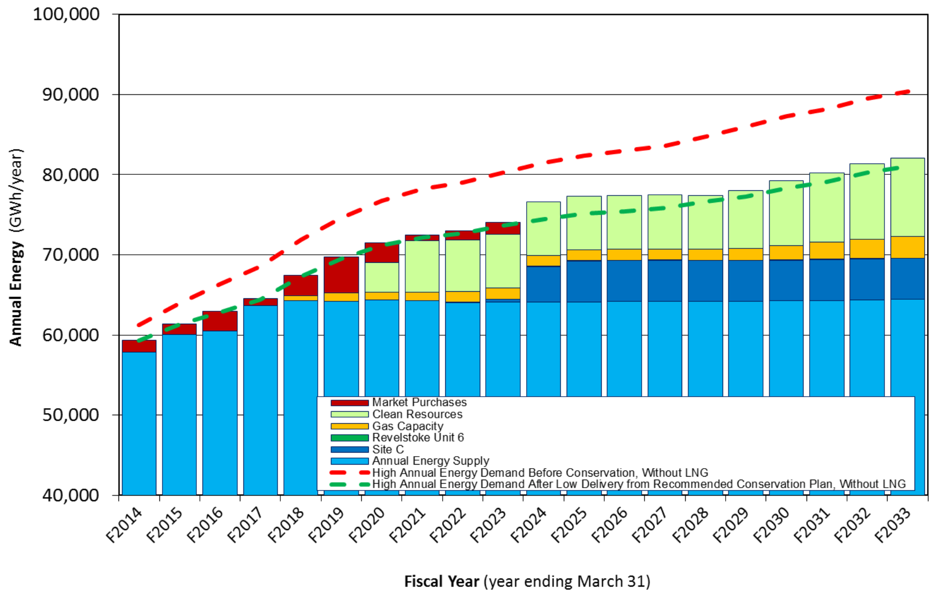
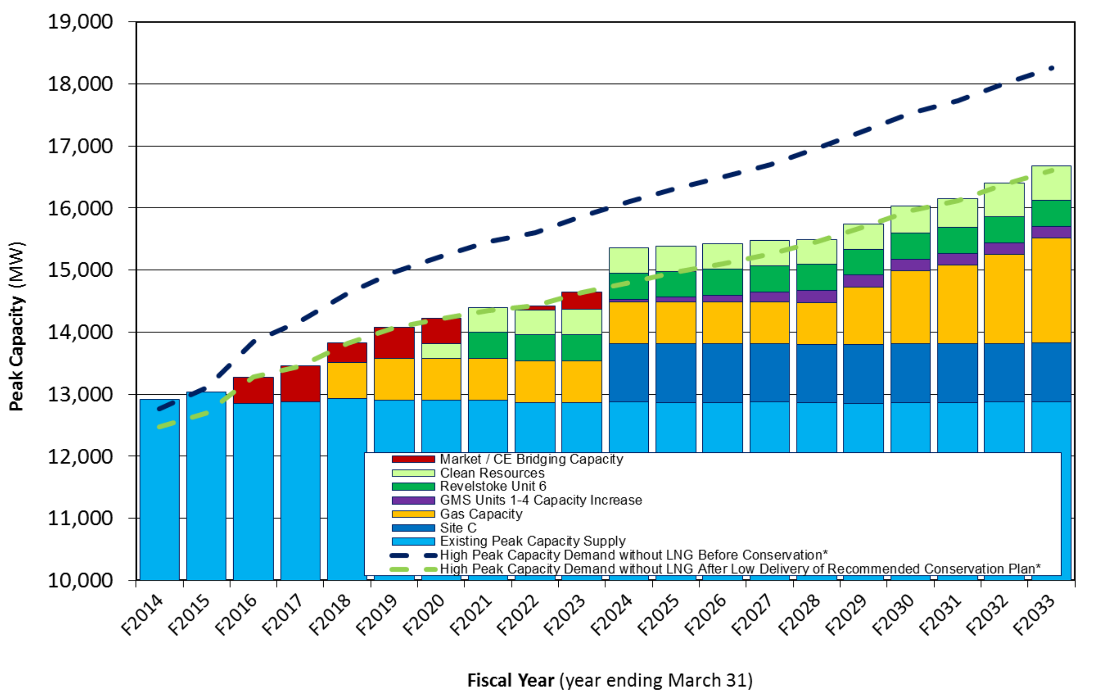


Figure 9-8 Capacity LRB for CRP1



* including planning reserve requirements

CRP1 shows how BC Hydro would plan to supply a high need for new resources. BC Hydro's main concern is to ensure adequate capacity is available to meet peak load requirements and to back up other generator-forced outages. As discussed in section 6.9, the lowest-cost capacity resources include Revelstoke Unit 6, GMS Units 1-5 Capacity Increase and SCGTs; these resources are built into CRP1. If the higher gap occurs over a short time frame, it is likely that some gas-fired generation would be required along with some market reliance.

While energy supply shortfalls are a lesser concern than capacity from a reliability perspective, CRP1 would likely drive the need to advance up to about 7,000 GWh/year of clean energy acquisitions by F2023 in order to adhere to the *CEA*'s energy self-sufficiency objective.

9.4.6 CRP2

CRP2 adds Expected LNG to the loads that need to be supplied. The resulting portfolio that BC Hydro would plan to build is shown in Figure 9-9 and Figure 9-10.

Figure 9-9 Energy LRB for CRP2

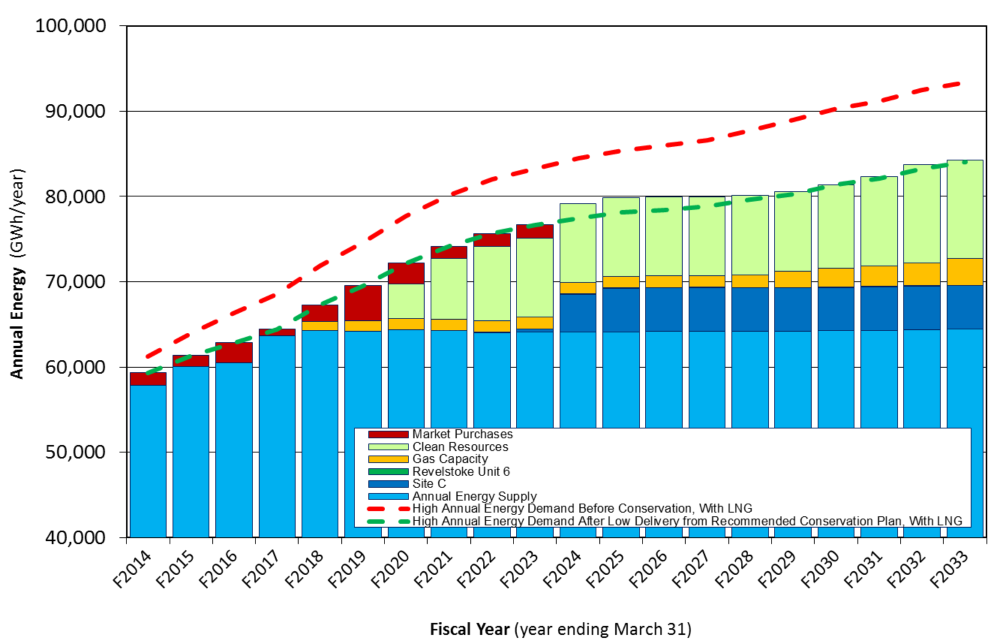
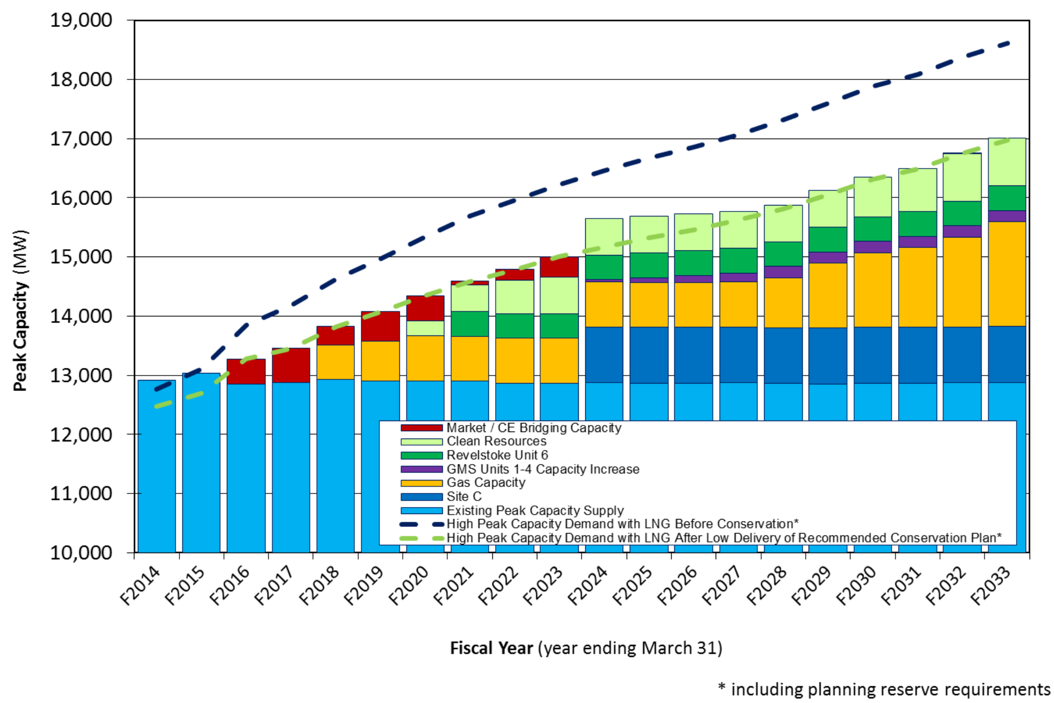


Figure 9-10 Capacity LRB for CRP2



The preceding CRP2 graphs show that generally more natural gas-fired generation is required. The rationale for CRP2 is to highlight and drive the incremental transmission resources that would be required for the Expected LNG case.

BC Hydro contemplated having a scenario with both high LNG and non-LNG load; however, the analysis done in Chapter 6 on the North Coast region suggested that it would be unlikely that a second 500 kV transmission line would be required. Rather, it is anticipated that additional LNG would be supported by natural gas-fired generation on the North Coast.

9.4.7 Recommended Action 18: Investigate Fort Nelson area supply options

Investigate procurement options to serve future Fort Nelson load.

Recommended Action 13 addresses electrification of the larger Horn River Basin, which would include the Fort Nelson region. In the absence of clarity on HRB electrification, BC Hydro must continue to be prepared to supply loads in the Fort Nelson region as described in Chapter 2.

BC Hydro recommends that it continue to address the Fort Nelson area requirements in the following fashion:

- BC Hydro will maintain N-1 level of service to the Fort Nelson area over the long term. With that in mind, and in light of load forecast uncertainties, BC Hydro will avoid new supply commitments until load growth signals become more certain.
- As a bridging strategy, and to the extent that relatively sizeable industrial loads materialize earlier than expected, BC Hydro will provide interruptible (N-0) service to such loads on a temporary basis until such time as N-1 service becomes available. BC Hydro would be able to serve up to 112 MW of load with combined Fort Nelson Generating Station (**FNG**) and Alberta supply on an interruptible (N-0) basis.
- BC Hydro will continue to monitor Fort Nelson area load growth including signposts for load developments and on-the-ground market intelligence
- BC Hydro will continue to investigate and engage in actions concerning the range of potential supply options, including implementation in collaboration with Alberta of a Fort Nelson Load Shedding Remedial Action Scheme (**LSRAS**) and assessment of local natural gas-fired generation options to meet the range of forecast capacity shortfall

9.4.7.1 Justification

In the mid load scenario, the load is expected to grow from its current level of about 30 MW (as measured by winter peak capacity) to about 43 MW by F2020 reaching the N-1 threshold for planning purposes by about F2018 or F2019.

While BC Hydro expects load growth to be modest over the next five years (F2014- F2018), there are significant uncertainties to the forecast due to potential impacts from HRB development and/or other unexpected load developments. These uncertainties could defer the expected capacity shortfall to beyond F2018, or cause the shortfall to occur earlier than F2018.

Given the substantial near-term load forecast uncertainties, BC Hydro is not willing to make a significant investment commitment at this point. BC Hydro is taking actions to address these uncertainties and set the stage for longer-term planning actions as well, without losing sight of natural gas industry and HRB developments. These actions will include the close monitoring of Fort Nelson area load in order to reflect these changes into its load forecast and its servicing plans.

9.4.7.2 Execution

Key activities include:

- In collaboration with the Alberta Electric System Operator (**AESO**) and ATCO Power, complete in F2014 design and implementation of Fort Nelson LSRAS that will allow BC Hydro to serve increased load on an interruptible basis until additional supply is added. Estimated Cost: $2 million
- BC Hydro will refine the assessment of identified options to meet the range of forecast capacity shortfall, including the option of expanding the existing FNG by adding a second unit. Resource requirements will be primarily for staff time and potential for external consulting support in the range of $50,000 to $100,000.

9.4.7.3 Future Approval Process

No material regulatory approval processes are envisioned at this time given the scope of the Recommended Action.

The near-term costs associated with the Recommended Actions to correspond to the LRBs in the CRPs are outlined in Table 9-16.

Table 9-16 F2014 to F2016 CRPs Recommended Action Execution Expenditure

Recommended Action		Near-Term Execution Expenditure (in $F2013)			
		Applicability	F2014	F2015	F2016
Supply-Side Resources	15. Advance Revelstoke Unit 6 Resource Smart project	To ensure in-service date availability	$2.4 million	$2.4 million	$2.4 million
	16. Advance GM Shrum Resource Smart project	To determine Identification Phase feasibility	N/A	Up to $0.4 million	Up to $0.4 million
	17. Investigate natural gas-fired generation for capacity	N/A			
Other	18. Investigate Fort Nelson area supply options	To assess options to meet forecast capacity shortfall	$50,000 to $100,000		

9.4.8 Transmission Contingency Plans

The TCPs are intended to address the key transmission shortages that impact BC Hydro's resource plans. As demonstrated in section 6.8.6, there do not appear to be any bulk transmission regions that would cause BC Hydro supply concerns over the next 10 years.

9.5 Additional IRP Recommendations

9.5.1 Province-Wide Electrification/GHG Reduction Initiatives

Aside from the strategic planning electrification actions in support of the Clean Energy Strategy, as outlined in Recommended Action 10, section 9.2.12; section 6.7 also addresses the potential implications of the *CEA* GHG-related objectives that could drive general electrification across the economy, in end-uses such as space and water heating, passenger and freight vehicles, and industrial equipment (e.g., large compressors).

The potential costs and impacts of general electrification would be significant. BC Hydro will undertake preparatory actions and incur low costs:

- Continue to provide analysis and support to the B.C. Government to identify where electrification would be expected to occur in response to climate policy
- Continue distribution system studies and related activities, in conjunction with smart meters and smart grid implementation, to ensure that BC Hydro's transmission and distribution infrastructure is able to supply the increased loads (e.g., electric vehicles, heat pumps, distributed generation, load curtailment) that could result from significant electrification

BC Hydro's ongoing efforts to monitor provincial, national and international climate policy developments and analyze potential system demand will facilitate responding to potential future policy-driven electrification initiatives.

9.5.2 Export Market Analysis

Section 5.8 of this IRP provides an analysis of potential export market opportunities. The key conclusion is that market conditions do not justify the development of new, additional clean or renewable resources for the export market. Since the conditions underpinning these market dynamics are expected to persist for the foreseeable future, BC Hydro anticipates no incremental expenditures for export but will continue to monitor the export markets for future opportunities.

9.5.3 Transmission Planning for Generation Clusters

In section 6.9, the IRP evaluated the nine regions in B.C. that had the highest resource clean or renewable generation density (generation clusters) that may benefit from the pre-building of new bulk transmission to result in a more cost-effective transmission system development with a reduced environmental footprint. The analysis pointed to the potential to somewhat reduce environmental footprints as a result of optimal transmission configurations. However, there is only a marginal financial benefit associated with developing clusters to meet customer demand. In addition, there is a significant uncertainty over which resource options will ultimately be developed. As such, BC Hydro will consider transmission advancement for generation clusters during power acquisition processes when projects in these cluster regions are being bid.

9.5.4 IRP Submission Cycle and Amendments

Subsection 3(6)(b) of the *CEA* provides that subsequent IRPs must be submitted every five years after submission of this first IRP unless a submission date is prescribed by LGIC regulation. The submission date for the next IRP is August 2018 in the absence of such a regulation.

Subsection 3(7) of the *CEA* enables BC Hydro to submit an amendment to an approved IRP. BC Hydro plans to review the IRP in the fall of 2015, at which time BC Hydro expects to have further information concerning, among other things: (1) DSM delivery including any CPR results; (2) EPA renewal pricing and volumes; (3) an environmental assessment decision concerning Site C from the B.C. Ministers of Environment and of Forests, Lands and Natural Resource Operations, and the federal Minister of Environment; and (4) LNG proponent decisions to take service from BC Hydro and/or final investment decisions. A decision to submit an amendment prior to the next IRP will depend on the outcome of this review, which BC Hydro plans on sharing with interested parties including IRP Technical Advisory Committee members, First Nations and the public.

EXHIBIT B

Independent Power Producers (IPPs) currently supplying power to BC Hydro

As of October 1, 2015, BC Hydro has 105 Electricity Purchase Agreements (EPAs) with IPPs whose projects are currently delivering power to BC Hydro. These projects represent 18,902 gigawatt hours of annual supply and 4,606 megawatts of capacity. For information on IPPs who have an EPA with BC Hydro but are not yet in operation, please refer to the IPP Supply List – In Development document posted to our website.

Project Name	IPP/Seller	Location	Type	Call Process	Capacity (MW)	Energy (GWh/yr)
Coats IPP	Crofter's Gleann Enterprises	Gabriola Island	Non-Storage Hydro	1985 Negotiated EPA	< 0.5	1
Ocean Falls	Boralex Ocean Falls LP	Bella Bella	Non-Storage Hydro	1985 Non-Integrated Areas RFP	15	12
Mamquam Hydro	Atlantic Power Preferred Equity Ltd.	Squamish	Non-Storage Hydro	1988 Greater Than 5 MW	58	250
NWE Williams Lake WW	Atlantic Power Preferred Equity Ltd.	Williams Lake	Biomass	1988 Greater Than 5 MW	68	545
McMahon Generating	McMahon Cogeneration Plant JV	Taylor	Gas-Fired Thermal	1988 Greater Than 5 MW	105	840
McDonald Ranch	McDonald Ranch & Lumber Ltd.	Grasmere	Non-Storage Hydro	1989 Less Than 5 MW	< 0.5	< 0.5
Morehead Creek	Morehead Valley Hydro Inc.	Williams Lake	Non-Storage Hydro	1989 Less Than 5 MW	< 0.5	< 0.5
Seaton Creek Hydro (Homestead)	Homestead Hydro Systems	New Denver	Non-Storage Hydro	1989 Less Than 5 MW	< 0.5	1
Doran Taylor	Doran Taylor Hydro (JV partnership)	Port Alberni	Non-Storage Hydro	1989 Less Than 5 MW	6	23
Robson Valley (Ptarmigan Creek - RBV)	Robson Valley Power Corporation	McBride	Non-Storage Hydro	1989 Less Than 5 MW	4	26
Boston Bar Hydro (Scuzzy Creek)	Boston Bar LP	Boston Bar	Non-Storage Hydro	1989 Less Than 5 MW	6	38
Akolkolex	Canadian Hydro Developers, Inc.	Revelstoke	Non-Storage Hydro	1989 Less Than 5 MW	10	50
Walden North	Walden Power Partnership	Lillooet	Non-Storage Hydro	1989 Less Than 5 MW	18	54
Brown Lake Hydro	Brown Miller Power LP	Prince Rupert	Storage Hydro	1989 Less Than 5 MW	7	57
Soo River	Soo River Hydro	Whistler	Non-Storage Hydro	1989 Less Than 5 MW	13	65
Salmon Inlet (Sechelt Creek SCG)	MPT Hydro LP	Sechelt	Non-Storage Hydro	1989 Less Than 5 MW	17	68
Moresby Lake (QCPC)	Atlantic Power Preferred Equity Ltd.	Sandspit	Storage Hydro	1989 Non-Integrated Areas RFP	6	20
Hluey Lake (SNP)	MPT Hydro LP	Dease Lake	Non-Storage Hydro	1993 Non-Integrated Areas RFP	3	5
Island Generation	V.I. Power LP	Campbell River	Gas-Fired Thermal	1994 RFP	275	2,300
Arrow Lakes Hydro	Arrow Lakes Power Corporation	Slocan	Storage Hydro	1998 Negotiated EPA	185	767
Hartland Landfill Gas Utilization	Capital Regional District	Saanich	Biogas	2000 RFP	2	15
Hystad Creek Hydro	Valemount Hydro LP	Valemount	Non-Storage Hydro	2000 RFP	6	20
Miller Creek Power	Brown Miller Power LP	Pemberton	Non-Storage Hydro	2000 RFP	30	118
Upper Mamquam Hydro	Canadian Hydro Developers, Inc.	Squamish	Non-Storage Hydro	2001 Greater Than 40 GWh	25	108
Rutherford Creek Hydro	Rutherford Creek Power LP	Pemberton	Non-Storage Hydro	2001 Greater Than 40 GWh	50	172
Pingston Creek	Canadian Hydro Developers Inc and GLP Pingston Creek LP	Revelstoke	Non-Storage Hydro	2001 Greater Than 40 GWh	45	193
Eagle Lake C2 Micro Hydro	Pacific Cascade Hydro Inc.	West Vancouver	Non-Storage Hydro	2001 Less Than 40 GWh	< 0.5	1
Hauer Creek (aka Tete)	Hauer Creek Power Inc.	Valemount	Non-Storage Hydro	2001 Less Than 40 GWh	2	13
Marion 3 Creek	Marion Creek Hydro Inc.	Port Alberni	Non-Storage Hydro	2001 Less Than 40 GWh	5	18
Mears Creek	Synex Energy Resources Ltd	Gold River	Non-Storage Hydro	2001 Less Than 40 GWh	4	20
South Sutton Creek	South Sutton Creek Hydro Inc.	Port Alberni	Non-Storage Hydro	2001 Less Than 40 GWh	5	26
Brandywine Creek Small Hydro	Rockford Energy Corp.	Whistler	Non-Storage Hydro	2001 Less Than 40 GWh	8	34
McNair Creek Hydro	McNair Creek Hydro LP	Sechelt	Non-Storage Hydro	2001 Less Than 40 GWh	10	38
Furry Creek	Furry Creek Power Ltd	Lions Bay	Non-Storage Hydro	2001 Less Than 40 GWh	10	40
Vancouver Landfill Gas Utilization - Ph 1	VF Clean Energy, Inc.	Delta	Biogas	2001 Less Than 40 GWh	6	40
Vancouver Landfill Gas Utilization - Ph 2	VF Clean Energy, Inc.	Delta	Biogas	2003 Green Power Generation	2	15
China Creek Small Hydroelectric	Upnit Power LP	Port Alberni	Non-Storage Hydro	2003 Green Power Generation	6	25
South Cranberry Creek	Advanced Energy Systems 1 LP	Revelstoke	Non-Storage Hydro	2003 Green Power Generation	9	26
Zeballos Lake	Zeballos Lake Hydro LP	Zeballos	Storage Hydro	2003 Green Power Generation	22	93
Brilliant Expansion 1	Brilliant Expansion Power Corporation	Castlegar	Storage Hydro	2003 Green Power Generation	120	203
Ashlu Creek Water Power	Ashlu Creek Investments LP	Squamish	Non-Storage Hydro	2003 Green Power Generation	50	269
Pine Creek (Atlin)	XEITL LP	Atlin	Non-Storage Hydro	2006 Non-Integrated Areas RFP	2	5
Eldorado Reservoir	District of Lake Country	Kelowna	Storage Hydro	2006 Open Call	1	4
Barr Creek	Barr Creek LP	Tahsis	Non-Storage Hydro	2006 Open Call	4	16
Sakwi Creek Run of River	Sakwi Creek Hydro LP	Agassiz	Non-Storage Hydro	2006 Open Call	6	21
Raging River 2	Raging River Power & Mining Inc.	Port Alice	Storage Hydro	2006 Open Call	8	30
150 Mile House ERG	EnPower Green Energy Generation LP	150 Mile House	Energy Recovery Generation	2006 Open Call	6	34
Savona ERG	EnPower Green Energy Generation LP	Savona	Energy Recovery Generation	2006 Open Call	6	41
Lower Clowhom	Clowhom Power L.P.	Sechelt	Non-Storage Hydro	2006 Open Call	11	48
Upper Clowhom	Clowhom Power L.P.	Sechelt	Non-Storage Hydro	2006 Open Call	11	48
Tyson Creek Hydro	Tyson Creek Hydro Power Corp.	Sechelt	Storage Hydro	2006 Open Call	9	54
Bone Creek Hydro	Valisa Energy Inc.	Kamloops	Non-Storage Hydro	2006 Open Call	20	81

Project Name	IPP/Seller	Location	Type	Call Process	Capacity (MW)	Energy (GWh/yr)
Bear Mountain Wind Park	Bear Mountain Wind LP	Dawson Creek	Wind	2006 Open Call	102	197
Kwoiek Creek Hydroelectric	Kwoiek Creek Resources LP	Lytton	Non-Storage Hydro	2006 Open Call	50	223
Brilliant Expansion 2	Brilliant Expansion Power Corporation	Castlegar	Storage Hydro	2006 Open Call	< 0.5	226
Upper Stave Energy	Innergex Renewable Energy Inc. (QC)	Mission	Non-Storage Hydro	2006 Open Call	60	264
Kwalsa Energy	Innergex Renewable Energy Inc. (QC)	Mission	Non-Storage Hydro	2006 Open Call	90	384
East Toba and Montrose	Toba Montrose General Partnership	Powell River	Non-Storage Hydro	2006 Open Call	196	715
Alcan Long Term Electricity Purchase	Rio Tinto Alcan Inc.	Kitimat	Storage Hydro	2007 Negotiated EPA	896	3,307
PGP Bio Energy Project	Canfor Pulp Ltd.	Prince George	Biomass	2008 Bioenergy Call	60	123
Celgar Green Energy	Zellstoff Celgar LP	Castlegar	Biomass	2008 Bioenergy Call	78	242
Cedar Road LFG	Cedar Road LFG Inc.	Nanaimo	Biogas	2008 Standing Offer Program	1	11
Cypress Creek	Synex Energy Resources Ltd	Gold River	Non-Storage Hydro	2008 Standing Offer Program	3	12
Canoe Creek Hydro	Canoe Creek Hydro Company	Ucluelet	Non-Storage Hydro	2008 Standing Offer Program	6	16
Fitzsimmons Creek	Fitzsimmons Creek Hydro LP	Whistler	Non-Storage Hydro	2008 Standing Offer Program	8	36
Lower Bear Hydro	Bear Hydro LP	Sechelt	Non-Storage Hydro	2008 Standing Offer Program	10	46
Upper Bear Hydro	Bear Hydro LP	Sechelt	Non-Storage Hydro	2008 Standing Offer Program	10	73
Armstrong Wood Waste Co-Gen (RVG)	Tolko Industries Ltd.	Armstrong	Biomass	2009 Negotiated EPA	20	163
Skookumchuck Power Project	Skookumchuck Pulp Inc.	Skookumchuck	Biomass	2009 Negotiated EPA	51	267
Dokie Wind	Dokie General Partnership	Chetwynd	Wind	2009 Negotiated EPA	144	375
Chetwynd Biomass	West Fraser Mills Ltd.	Chetwynd	Biomass	2010 Bio Energy Ph 2	12	96
Fraser Lake Biomass	West Fraser Mills Ltd.	Fraser Lake	Biomass	2010 Bio Energy Ph 2	12	96
Fraser Richmond Soil and Fibre	Fraser Richmond Soil & Fibre Ltd.	Richmond	Biogas	2010 CBB	1	8
Castle Creek (formerly Benjamin Creek)	Castle Mountain Hydro Ltd.	McBride	Non-Storage Hydro	2010 Clean Power Call	6	34
Northwest Stave River	Northwest Stave River Hydro LP	Mission	Non-Storage Hydro	2010 Clean Power Call	18	65
Crowsnest Pass	Kensington Crowsnest Power L.P.	Sparwood	Energy Recovery Generation	2010 Clean Power Call	11	65
Jamie Creek	Jamie Creek LP	Gold Bridge	Non-Storage Hydro	2010 Clean Power Call	21	74
Dasque - Middle	Swift Power LP	Terrace	Non-Storage Hydro	2010 Clean Power Call	20	81
Skookum Power (aka Mamquam Skookum)	Skookum Creek Power Partnership	Squamish	Non-Storage Hydro	2010 Clean Power Call	25	102
Long Lake Hydro	Long Lake Joint Venture	Stewart	Storage Hydro	2010 Clean Power Call	31	153
Kokish River	Kwagis Power LP	Port McNeil	Non-Storage Hydro	2010 Clean Power Call	45	175
Cape Scott (formerly Knob Hill Wind)	Cape Scott Wind Farm Inc.	Port Hardy	Wind	2010 Clean Power Call	99	316
Quality Wind	Capital Power L.P.	Tumbler Ridge	Wind	2010 Clean Power Call	142	477
Intercon Green Power	Canfor Pulp LP	Prince George	Biomass	2010 Integrated Power Offer	32	73
Northwood Green Power	Canfor Pulp Ltd.	Prince George	Biomass	2010 Integrated Power Offer	63	104
Powell River Generation	Catalyst Paper, general partnership	Powell River	Biomass	2010 Integrated Power Offer	38	158
Cariboo Pulp and Paper	Cariboo Pulp and Paper Company	Quesnel	Biomass	2010 Integrated Power Offer	61	172
Harmac Biomass	Nanaimo Forest Products Ltd.	Nanaimo	Biomass	2010 Integrated Power Offer	55	209
Kamloops Green Energy	Domtar Inc.	Kamloops	Biomass	2010 Integrated Power Offer	76	288
Howe Sound Green Energy	Howe Sound Pulp and Paper Corporation	Port Mellon	Biomass	2010 Integrated Power Offer	112	400
Volcano Creek	Coast Mountain Hydro LP	Stewart	Non-Storage Hydro	2010 Negotiated EPA	18	51
Waneta Expansion	Waneta Expansion LP	Trail	Non-Storage Hydro	2010 Negotiated EPA	335	627
Forrest Kerr Hydroelectric	Coast Mountain Hydro LP	Stewart	Non-Storage Hydro	2010 Negotiated EPA	195	935
Nanaimo Reservoir #1 Energy Recovery	City of Nanaimo	Nanaimo	Energy Recovery Generation	2010 Standing Offer Program	< 0.5	1
Greater Nanaimo PCC Cogeneration	Regional District of Nanaimo	Nanaimo	Biogas	2010 Standing Offer Program	< 0.5	2
SunMine	City of Kimberley	Kimberley	Solar	2010 Standing Offer Program	1	2
LP Golden Biomass	Louisiana-Pacific Canada Ltd.	Golden	Biomass	2010 Standing Offer Program	8	4
South Cranberry Creek 2	Advanced Energy Systems 1 LP	Revelstoke	Non-Storage Hydro	2010 Standing Offer Program	< 0.5	6
Tolko Kelowna Cogeneration	Tolko Industries Ltd.	Kelowna	Biomass	2010 Standing Offer Program	15	11
Squamish Power Project	Woodfibre LNG Limited	Squamish	Storage Hydro	2010 Standing Offer Program	1	11
Haa-ak-suuk Creek Hydro	Haa-ak-suuk Creek Hydro LP	Ucluelet	Non-Storage Hydro	2010 Standing Offer Program	6	21
Cache Creek Landfill Gas Utilization Plant	Wastech Services Ltd.	Cache Creek	Biogas	2010 Standing Offer Program	5	36
East Twin Creek Hydro	Valemount Hydro LP	McBride	Non-Storage Hydro	2011 Negotiated EPA	2	6
Conifex Green Energy	Conifex Power Inc.	Mackenzie	Biomass	2011 Negotiated EPA	36	209
SEEGEN (Burnaby Incinerator)	Covanta Burnaby Renewable Energy, ULC	Burnaby	Municipal Solid Waste	2014 Negotiated EPA	25	166
105 EPAs					**4,606**	**18,902**

EXHIBIT C

Independent Power Producers (IPPs) with projects currently in development

As of October 1, 2015, BC Hydro has 23 Electricity Purchase Agreements (EPAs) with IPPs whose projects are currently in development. These projects represent 3,098 gigawatt hours of annual supply and 754 megawatts of capacity. For information on IPPs who have an EPA with BC Hydro and are in operation, please refer to the IPP Supply List – In Operation document posted to our website.

Project Name	Owner	Location	Type	Call Process	Capacity (MW)	Energy (GWh/yr)
Fries Creek	Fries Creek Hydro Limited Partnership	Squamish	Non-Storage Hydro	2006 Open Call	9	41
Cranberry Creek Power	Advanced Energy Systems Ltd.	Revelstoke	Non-Storage Hydro	2006 Open Call	3	9
Fort St. James Green Energy	Fort St. James Green Energy Limited Partnership	Fort St. James	Biomass	2010 Bio Energy Ph 2	40	289
Merritt Green Energy	Merritt Green Energy Limited Partnership	Merritt	Biomass	2010 Bio Energy Ph 2	40	289
Ramonas - CC Creek - Chickwat	NI Hydro Holding Corp.	Sechelt	Storage Hydro	2010 Clean Power Call	33	148
Big Silver - Shovel Creek	Innergex Renewable Energy Inc. (QC)	Harrison Hot Springs	Non-Storage Hydro	2010 Clean Power Call	41	159
Upper Toba Valley	Upper Toba General Partnership	Powell River	Non-Storage Hydro	2010 Clean Power Call	62	174
Bremner - Trio	Greengen Holdings Ltd.	Harrison Hot Springs	Non-Storage Hydro	2010 Clean Power Call	45	204
Upper Lillooet River	Upper Lillooet River Power Limited Partnership	Pemberton	Non-Storage Hydro	2010 Clean Power Call	81	334
Box Canyon	Box Canyon Hydro Corporation, Sound Energy Inc.	Port Mellon	Non-Storage Hydro	2010 Clean Power Call	15	47
Meikle Wind	Meikle Wind Energy Limited Partnership	Tumbler Ridge	Wind	2010 Clean Power Call	185	588
Culliton Creek	Culliton Creek Power Limited Partnership	Squamish	Non-Storage Hydro	2010 Clean Power Call	15	74
Tretheway Creek	Innergex Renewable Energy Inc. (QC)	Mission	Non-Storage Hydro	2010 Clean Power Call	21	81
Boulder Creek	Boulder Creek Power Limited Partnership	Pemberton	Non-Storage Hydro	2010 Clean Power Call	25	92
McLymont Creek	Coast Mountain Hydro Limited Partnership	Stewart	Non-Storage Hydro	2010 Negotiated EPA	66	244
Wedgemount Creek IPP	Wedgemount Power Limited Partnership	Whistler	Non-Storage Hydro	2010 Standing Offer Program	5	20
McIntosh Creek Waterpower Project	Snowshoe Power Ltd.	McBride	Non-Storage Hydro	2010 Standing Offer Program	1	4
Septimus Creek Wind Farm	Zero Emissions Septimus Creek Limited Partnership	Taylor	Wind	2010 Standing Offer Program	15	49
Pennask Wind Farm	Zero Emissions Pennask Limited Partnership	Westbank	Wind	2010 Standing Offer Program	15	50
Shinish Creek Wind Farm	Zero Emissions Shinish Creek Limited Partnership	Summerland	Wind	2010 Standing Offer Program	15	55
Gabion River EPA (Hartley Bay)	Gitga'at Economic Limited Partnership	Hartley Bay	Storage Hydro	2012 Non-Integrated Areas RFP	1	2
Houweling Nurseries (Delta) Cogeneration	Houweling Nurseries Ltd.	Delta	Gas-Fired Thermal	2014 Negotiated EPA	9	65
Conifex Mackenzie - Combined Heat and Power Project	Conifex MacKenzie Forest Products Inc.	Mackenzie	Gas-Fired Thermal	2014 Negotiated EPA	11	82
23 EPAs					**754**	**3,098**

EXHIBIT D

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February 18, 2016

Ms. Erica Hamilton
Commission Secretary
British Columbia Utilities Commission
Sixth Floor – 900 Howe Street
Vancouver, BC V6Z 2N3

Dear Ms. Hamilton:

RE: Project No. 3698781
British Columbia Utilities Commission (BCUC or Commission)
British Columbia Hydro and Power Authority (BC Hydro)
2015 Rate Design Application (2015 RDA)
Load Resource Balance and Long-Run Marginal Cost

BC Hydro writes in compliance with Commission Order No. G-12-16 and submits its Evidentiary update of BC Hydro's Load Resource Balance and Long-Run Marginal Cost.

The energy Long-Run Marginal Cost determination is an important reference point for a number of BC Hydro's rate structures, most notably the Residential Inclining Block Rate and the Transmission Service Stepped Rate.

The Long-Run Marginal Cost is determined by the cost of BC Hydro's marginal energy resources. Consistent with the 2013 IRP, over the planning horizon the marginal need for new energy resources is expected to be met by Demand Side Management and Independent Power Producer Energy Purchase Agreement renewals. Given the updated Load Resource Balance and cost of supply outlook, BC Hydro's current view on the energy Long-Run Marginal Cost has shifted towards $85/MWh from $85 to $100/MWh. The potential further changes to the Load Resource Balance noted below are not expected to impact the Long-Run Marginal Cost any further because those changes are unlikely to result in a change to the marginal resources over the planning horizon.

The Load Resource Balance and Load Forecast provided in this Evidentiary Update are 20-year forecasts which were finalized in October 2015. The Load Forecast continues to show long-term load growth across the residential, commercial and industrial customer classes; however, the load is forecast at a lower level compared to the 2013 Integrated Resource Plan.

The Load Forecast and Load Resource Balance do not reflect more recent information that is expected to be material.

In certain sectors, our industrial customers have been faced with significant declines in prices for the commodities they produce. There have also been more recent developments with respect to liquefied natural gas load including the announcement of the deferral of a final investment decision on a liquefied natural gas project. Additionally, on February 5, 2016 the Government of British Columbia announced a program to allow mining companies to defer a portion of their electricity payments, to help mines stay open.

Given the possible significance of these recent developments, BC Hydro believes it is prudent to undertake an additional update. Accordingly, the Load Resource Balance and Load Forecast provided in this Evidentiary Update are under review with an update to be completed this summer, including changes in the mining and liquefied natural gas sectors. BC Hydro will file the updated Load Resource Balance and Load Forecast as an Evidentiary Update.

For further information, please contact Gordon Doyle at 604-623-3815 or by email at bchydroregulatorygroup@bchydro.com.

Yours sincerely,

Tom Loski
Chief Regulatory Officer

gd/ma

Copy to: BCUC Project No. 3698781 (2015 RDA) Registered Intervener Distribution List.

Rate Design Application

Evidentiary Update on Load Resource Balance

and Long Run Marginal Cost

Table of Contents

List of Tables

1 Introduction

BC Hydro's Long-Run Marginal Cost (**LRMC**) for energy in British Columbia is updated to $85/MWh ($F2013) from $85 to $100/MWh ($F2013) and for capacity it remains at $50 to 55/kW-year($F2013).

The October 2015 Load Resource Balance (**LRB**) and Load Forecast referenced in this submission reflect BC Hydro's most recent detailed analysis. The Load Forecast continues to show long-term load growth across the residential, commercial and industrial customer classes; however, load is forecast at a lower level compared to the 2013 IRP. These forecasts do not reflect more recent information that is expected to materially change the Load Forecast and LRB.

In certain sectors, our industrial customers have been faced with significant declines in prices for the commodities they produce. There have also been more recent developments with respect to liquefied natural gas (**LNG**) load including the announcement of the deferral of a final investment decision on a LNG project. Additionally, on February 5, 2016 the Government of British Columbia announced a program to allow mining companies to defer a portion of their electricity payments, to help mines stay open. The LRB and Load Forecast referenced in this document are under review with an update to be completed in summer of 2016, including changes in the mining and LNG sectors. BC Hydro will file the updated LRB and Load Forecast as an Evidentiary Update.

The energy LRMC of $85/MWh is based on BC Hydro's assessment that it can acquire what it needs in the plan from its marginal resources, Demand Side Management (**DSM**) and electricity purchase agreement (**EPA**) renewals with IPPs at or below $85/MWh. The energy LRMC has changed to the lower end of the previous range based upon updated information on both the reduced need for new resources and the anticipated costs of IPP EPA renewals. The capacity LRMC continues to be based upon the cost of Revelstoke Unit 6.

The potential further changes to the LRB noted above are not expected to impact the LRMC because those changes are unlikely to result in DSM, IPP EPA renewals and Revelstoke Unit 6 no longer being the marginal resources over the next ten years.

1.1 LRMC Definition, Determination and Application

The Integrated Resource Plan (**IRP**) is BC Hydro's long term planning document that sets out recommended actions to ensure our customers will continue to receive cost effective, reliable electricity with manageable risks, consistent with the requirements and objectives of the *Clean Energy Act*. BC Hydro's 2013 IRP has 18 Recommended Actions that BC Hydro is taking to ensure we can reliably and cost effectively supply our customers' load requirements under expected (or base) conditions and contingency conditions. The 2013 IRP was approved by the Lieutenant Governor in Council in November 2013.

The LRB gap is the difference between BC Hydro's forecast load and forecast supply. The LRB gap with existing and committed resources[1] in the context of the approved IRP drives the need for resources such as DSM savings, IPP contract renewals and acquisitions.

In general, LRMC can be defined as the price of the most cost-effective way of satisfying incremental customer demand beyond existing and committed resources[2] as guided by the government approved IRP which ensures reliable and cost effective electricity service both in the near and long-term while balancing multiple policy objectives. BC Hydro typically expresses this as a levelized unit cost (i.e., Unit Energy

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1 Existing supply-side resources include BC Hydro's Heritage hydroelectric and thermal generating resources, as well as IPP facilities delivering electricity to BC Hydro. Committed supply-side resources are resources for which material regulatory and BC Hydro executive approvals have been secured (including Site C).

2 2013 IRP, page 9-51.

Cost or Unit Capacity Cost). Once established, the LRMC is used as a reference price by BC Hydro to inform the value that should be placed upon acquiring new resources such as IPP acquisitions, DSM savings, Resource Smart; and equipment efficiency and loss valuations, where there is a need.

The LRMC is meant to set a steady price signal to allow consistency in determining/screening the cost effectiveness of different resources. BC Hydro also uses LRMC as a basis for the step 2 rate of certain rate structures to maintain a steady price signal encouraging conservation.

BC Hydro does not expect to acquire all available resources up to the LRMC nor does it expect the LRMC to be the clearing price. This approach is consistent with previous acquisition processes where BC Hydro did not acquire all energy that could be purchased at a particular price; rather acquisitions were made for particular volumes of energy informed by need. Given the reduced need for new energy resources going forward, BC Hydro is not expecting to further adjust the LRMC to reduce resource acquisitions, but is increasingly focusing on non-price factors (e.g., non-price factors for supply-side resource include benefits to the system and non-price factors for demand-side resource include providing opportunities for customers across rate classes). We have also shifted the focus of our DSM efforts in consideration of opportunities to reduce costs, be innovative and take advantage of new technologies, and respond to changing customer expectations and system needs. Details of our DSM plan for F2017 to F2019 will be provided in the revenue requirements application.

1.2 LRB – October 2015 Load Forecast

Table 1 to Table 4 show the LRB that includes the October 2015 Load Forecast. Table 1 and Table 2 show the LRB with only existing and committed resources prior to additional planned resource acquisitions. New resources are needed both for energy and capacity at the start of the planning horizon (F2020)[3] on an expected basis. Table 3 and Table 4 show the LRB including planned resource acquisitions. Given uncertainty in input assumptions that drive the LRB gap and future resource requirements, each table shows an expected LRB gap as well as a range of results reflecting load forecast and DSM savings uncertainty where applicable.[4] Note that in all cases, the same forecast LNG load is shown.

Since the 2013 IRP, the LRB has evolved. The load forecast continues to show long-term load growth across all three customer classes; however, load is forecast at a lower level compared to the 2013 IRP. DSM savings from conservation rate structures are lower than expected, energy savings from codes and standards have increased, and the IPP energy delivery forecast has increased. The capacity LRB has further evolved with major maintenance requirements on the existing system related to the required refurbishment of generating units 1 to 4 at the Mica generating station. The overall result is a reduced need for energy resources, a reduced need for capacity resources prior to Site C and an increased need for capacity resources after Site C.

Load Forecast

The October 2015 Load Forecast predicts long-term load growth for all three customer sectors. Residential and commercial loads are growing steadily albeit at a slower rate since the 2009 recession, primarily driven by increasing population and general economic trends. Large industrial load growth continues to be subject to volatility and will require continued evaluation. Overall, however, load is forecast at a lower level relative to the 2013 IRP:

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3 BC Hydro shows the load resource balance in two views. The planning horizon (F2020 and beyond) reflects the forecast of system need under prescribed water conditions set out in the self-sufficiency requirement contained in subsection 6(2) of the *Clean Energy Act*. The forecast in the operating horizon (F2017 to F2019) provides the forecasted optimal reliance on resources in the short-term given near-term market conditions, system constraints, planned outages and expected hydro reservoir inflows.

4 BC Hydro quantified a range of uncertainty for load forecast (prior to LNG) and DSM savings. The high and low load forecast estimates and DSM estimates are the mean of the upper and lower twentieth percentile tails of the respective distributions. High load forecast and Low DSM estimate are combined in the large gap scenario. Low load forecast and Low DSM estimate are combined in the small gap scenario.

- For the residential and commercial sectors, the lower forecast is primarily due to lower growth projections in economic drivers such as housing starts; and
- For the industrial sector, the lower forecast is due to factors including delays of in service dates for several mining, and oil and gas projects, reduced expectations for potential new mining and oil and gas loads given current low commodity prices, the closure of Paper Excellence's Howe Sound Thermo-Mechanical Pulp Facility, and a reduced outlook for the pulp and paper sector.

DSM Savings

DSM continues to be a key resource in the LRB and there have been two changes since the 2013 IRP. First, energy savings from conservation rate structures have been less than forecast, but energy savings from codes and standards have increased. In particular, customers' response to the Large General Service and Medium General Service two part baseline rates was considerably lower than forecast in the 2013 IRP. Most of the incremental energy savings from the LGS and MGS rates were forecasted to occur prior to F2015 and that impact is reflected in the current load forecast. Second, BC Hydro has decided to extend the moderation of DSM spending recommended in the 2013 IRP through F2017 – F2019.

IPP Forecasts

The forecast of IPP supply from existing electricity purchase agreements has increased largely due to higher than expected project advancements and completions.

Major Maintenance

BC Hydro's heritage assets are aging, requiring major maintenance work to ensure reliable operation. Given the capacity need and the cost effective strategy to rely on market as a bridging resource to Site C, BC Hydro has to delay major maintenance work to avoid taking major units out of service during the period when capacity is tight prior to Site C. The updated capacity LRB reflects the current view of scheduling maintenance outages for generating units 1 to 4 (410 MW each for dependable capacity) at the Mica generating station when Site C comes online. It is currently estimated that the units will be out of service for 12 to 18 months each. The resulting impact is a 410 MW reduction in capacity contribution from BC Hydro's heritage resources for a period of approximately six years which will advance BC Hydro's need for new capacity resources after Site C. The impact of the outage on energy is minimal.

2 Energy LRMC

Currently and still consistent with the 2013 IRP, BC Hydro's actions to meet future energy demand include Site C and the Standing Offer Program (**SOP**), along with DSM and IPP EPA renewals. Site C is a committed resource under construction and is not a marginal resource. Similarly, while the SOP is targeting new resources, it is not considered a marginal resource because it is required pursuant to subsection 15(2) of the *Clean Energy Act*.

As a result, DSM and IPP EPA renewals continue to be the marginal resources (energy volume adjustable) in the plan. As shown in Table 1, without DSM and IPP EPA renewals, there would be a need for new resources at the beginning of the planning horizon (i.e., F2020).

BC Hydro anticipates that it will continue to be able to acquire a sufficient volume of energy from these resources to meet its needs as identified in the 2013 IRP and updated in the LRB shown at Table 3 at a lower price than greenfield IPPs.[5] Since the DSM and IPP renewal resource supply curves (price and volume relationship) are not easily visible until the actions have been undertaken and as their prices are expected

[5] Current greenfield IPP prices are expected to be $100/MWh ($2015) based upon recent wind cost estimates reflecting adjusted unit energy cost including delivery to the LM/VI region.

to overlap, BC Hydro used a LRMC of $85/MWh to establish that there would be sufficient supply available from planned DSM initiatives and IPP EPA renewals.

BC Hydro’s current outlook on the LRMC has shifted towards $85/MWh because the need for new resources has reduced and the price outlook for marginal resources has dropped since the 2013 IRP.

EPA Renewals

Consistent with the 2013 IRP, BC Hydro continues to plan to acquire through renewed EPAs 50 per cent of the energy and capacity contributions of existing bioenergy EPAs and 75 per cent of the contributions of the existing run-of-river hydroelectric EPAs that are due to expire by F2024.

In its EPA renewal negotiations, BC Hydro will consider the seller’s opportunity cost, the electricity spot market, the cost of service for the seller’s plant and other factors such as the attributes of the energy produced (e.g., dependable capacity) and other non-energy benefits.

BC Hydro notes that the costs of service for IPPs could vary significantly. BC Hydro expects there will be cost differences between biomass EPA renewals and run-of-river EPA renewals because run-of-river hydroelectric projects are primarily civil works with costs that have been fully or largely recovered during the first EPA term and likely have minimal sustaining capital costs. Bioenergy projects will have greater ongoing costs for operations including the cost of biomass fuel. Bioenergy facilities contribute dependable capacity which has additional system value.

Since the 2013 IRP, BC Hydro has carried out further analysis of the expected cost of service for existing biomass (including the cost and availability of fuel supply) and run-of-river projects. Based upon this further information and a reduced need for new resources, BC Hydro currently estimates that the renewal volumes in the plan can be acquired at or below the LRMC of $85/MWh although the relationship between price, volume, contract terms and other non-energy benefits has yet to be established through bilateral negotiation.

DSM

The $85/MWh LRMC upper limit was used to inform the development of the DSM plan including by ensuring that all DSM initiatives were cost effective in a Total Resource Cost (**TRC**) test against the $85/MWh threshold.

Details of BC Hydro’s DSM plan for F2017 to F2019 will be included in the revenue requirements application. The DSM savings shown in the LRB beyond F2019 are an outlook for DSM activities, which will be further explored in the next IRP due in November 2018.

Capacity

Consistent with the 2013 IRP, the capacity LRB outlook in this document continues to show a need to acquire additional capacity resources over and above the other resource acquisitions in the plan. BC Hydro continues to base the LRMC for capacity resources on Revelstoke Unit 6 which is the most cost effective generation capacity resource on a unit cost basis (Unit Capacity Cost of $50 to $55/kW-year). The updated capacity LRB outlook in this document shows that the expected need for Revelstoke Unit 6 has been advanced to F2026 from F2030 in the 2013 IRP. At the same time, Revelstoke Unit 6 continues to be a contingency resource for capacity needs prior to Site C, requiring its earliest in service date (now estimated at F2022) to be maintained.

3 Conclusion

Consistent with the 2013 IRP, over the next ten years the marginal need for new energy resources is expected to be met by DSM and IPP EPA renewals. Given the LRB outlook, BC Hydro’s current outlook on the energy LRMC has shifted towards

$85/MWh because the need for new resources has reduced and the price outlook for marginal resources has dropped since the 2013 IRP.

The price signal provided to set the upper limit on those acquisitions is $85/MWh ($F2013) and BC Hydro expects it will be able to acquire sufficient resources to meet its need at or below the LRMC.

Revelstoke Unit 6 continues to be the marginal resource to meet the need for capacity resources. While Revelstoke Unit 6 is expected to be needed shortly after Site C, it is not yet a committed resource. As such, the current capacity LRMC will continue to be $50-55/kW-year($F2013) based on the levelized unit cost of Revelstoke Unit 6.

The potential further changes to the LRB noted in this document are not expected to impact the LRMC any further because those changes are unlikely to change the marginal energy and capacity resources over the next ten years. Furthermore, managing overall acquisitions can be done by limiting acquired volumes without modifying price limits

Updating the energy LRMC to $85/MWh may result in questions about what if any changes should be made to the Residential Inclining Block rate design. BC Hydro notes that a steady price signal is beneficial for encouraging a conservation culture. Additionally, as there is a continued need for capacity resources in the system, there may be merit in exploring the inclusion of a generation capacity value in the energy LRMC for the purpose of the Residential Inclining Block Step 2 rate. The addition of a generation capacity value to the energy LRMC could increase the LRMC for Residential Inclining Block from $95/MWh (based on $85/MWh in $F2013 adjusted for distribution losses and inflated to $2017) to $106/MWh in $F2017. BC Hydro proposes that these matters be explored further through this proceeding.

Table 1 Energy LRB with Existing and Committed Resources[6]

				Operating	Planning														
(GWh)		**F2017**	**F2018**	**F2019**	**F2020**	**F2021**	**F2022**	**F2023**	**F2024**	**F2025**	**F2026**	**F2027**	**F2028**	**F2029**	**F2030**	**F2031**	**F2032**	**F2033**	**F2034**
Existing and Committed Heritage Resources		46,935	46,054	46,228	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
Site-C									388	4,435	5,100	5,100	5,100	5,100	5,100	5,100	5,100	5,100	5,100
Sub-total	(a)	46,935	46,054	46,228	48,671	48,671	48,671	48,671	49,059	53,106	53,771	53,771	53,771	53,771	53,771	53,771	53,771	53,771	53,771
Existing and Committed IPP Resources	(b)	13,919	14,735	14,208	16,205	15,948	15,359	13,225	12,688	12,319	11,928	11,818	11,500	10,963	10,187	9,723	9,654	9,608	9,447
Total Supply	(c) = a + b	60,853	60,789	60,436	64,876	64,619	64,031	61,897	61,748	65,425	65,699	65,589	65,271	64,734	63,958	63,494	63,426	63,379	63,218
Demand - Integrated System Total Gross Requirements																			
2015 Oct Mid Load Forecast Before DSM*		-60,231	-61,866	-63,832	-65,432	-66,676	-67,843	-68,850	-69,650	-70,420	-71,440	-72,288	-73,316	-74,277	-75,292	-76,381	-77,515	-78,441	-79,350
Expected LNG Load		-289	-355	-518	-2,020	-2,544	-2,570	-3,000	-3,000	-3,000	-3,000	-3,000	-3,000	-3,000	-3,000	-3,000	-3,000	-3,000	-3,000
Sub-total	(d)	-60,520	-62,221	-64,350	-67,452	-69,220	-70,413	-71,850	-72,650	-73,420	-74,440	-75,288	-76,316	-77,277	-78,292	-79,381	-80,515	-81,441	-82,350
Demand Side Management & Other Measures																			
SMI Theft Reduction		193	193	193	193	193	193	193	193	193	193	193	193	193	193	193	193	193	193
2016 DSM Plan F15 and F16 savings		1,343	1,390	1,367	1,335	1,357	1,383	1,391	1,401	1,397	1,242	1,107	1,108	1,072	1,021	1,003	1,018	1,016	1,005
Sub-total	(e)	1,536	1,582	1,560	1,528	1,550	1,576	1,585	1,594	1,590	1,435	1,300	1,301	1,265	1,214	1,196	1,211	1,209	1,198
		F2017	**F2018**	**F2019**	**F2020**	**F2021**	**F2022**	**F2023**	**F2024**	**F2025**	**F2026**	**F2027**	**F2028**	**F2029**	**F2030**	**F2031**	**F2032**	**F2033**	**F2034**
Surplus / Deficit	(f) = c + d + e	**1,869**	**150**	**(2,355)**	**(1,048)**	**(3,051)**	**(4,807)**	**(8,369)**	**(9,308)**	**(6,405)**	**(7,306)**	**(8,398)**	**(9,743)**	**(11,277)**	**(13,120)**	**(14,690)**	**(15,879)**	**(16,853)**	**(17,934)**
Low Load Forecast Surplus / Deficit		4,842	4,479	3,333	5,833	4,584	3,507	224	(534)	2,673	2,101	1,387	234	(977)	(2,783)	(3,825)	(4,779)	(5,247)	(6,378)
High Load Forecast Surplus / Deficit		(1,110)	(4,340)	(8,496)	(8,635)	(11,547)	(13,752)	(17,783)	(18,964)	(16,645)	(17,942)	(19,324)	(20,974)	(22,804)	(24,962)	(26,687)	(28,317)	(29,754)	(31,135)

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6 BC Hydro typically shows the load resource balance in two views. The planning horizon (F2020 and beyond) reflects the forecast of system need under prescribed water conditions set out in the self-sufficiency requirement contained in subsection 6(2) of *the Clean Energy Act*. The start year is F2020 to reflect typical lead time considerations for making new long-term acquisitions. The forecast in the operating horizon (F2017 to F2019) provides the forecasted optimal reliance on resources in the short-term given near-term market conditions, system constraints, planned outages and inflows. Operational shortfalls may also be met through economic market purchases, greater use of natural gas-fired (thermal) generation resources or greater drawdown of major reservoirs.

Table 2 Peak Capacity LRB with Existing and Committed Resources

				Operating	Planning														
(MW)		**F2017**	**F2018**	**F2019**	**F2020**	**F2021**	**F2022**	**F2023**	**F2024**	**F2025**	**F2026**	**F2027**	**F2028**	**F2029**	**F2030**	**F2031**	**F2032**	**F2033**	**F2034**
Existing and Committed Heritage Resources		11,419	11,457	11,463	11,463	11,463	11,527	11,527	11,527	11,113	11,113	11,113	11,113	11,113	11,113	11,527	11,527	11,527	11,527
Site-C									0	1,100	1,100	1,100	1,100	1,100	1,100	1,100	1,100	1,100	1,100
Sub-total	(a)	11,419	11,457	11,463	11,463	11,463	11,527	11,527	11,527	12,213	12,213	12,213	12,213	12,213	12,213	12,627	12,627	12,627	12,627
Existing and Committed IPP Resources	(b)	1,688	1,664	1,601	1,552	1,530	1,453	1,165	1,121	1,059	1,017	1,017	968	930	798	798	794	788	764
14% of Supply Requiring Reserves	(c)	-1,806	-1,808	-1,801	-1,794	-1,790	-1,787	-1,746	-1,742	-1,837	-1,831	-1,831	-1,824	-1,819	-1,800	-1,858	-1,857	-1,857	-1,853
Effective Load Carrying Capability	(d) = a + b + c	11,300	11,312	11,263	11,221	11,203	11,193	10,945	10,905	11,435	11,399	11,399	11,357	11,325	11,211	11,567	11,563	11,558	11,537
Demand - Integrated System Peak																			
2015 Oct Mid Load Forecast Before DSM*		-11,022	-11,402	-11,628	-11,807	-12,021	-12,186	-12,340	-12,502	-12,690	-12,879	-13,084	-13,299	-13,518	-13,750	-13,985	-14,223	-14,464	-14,701
Expected LNG Load		-45	-45	-95	-285	-326	-326	-380	-380	-380	-380	-380	-380	-380	-380	-380	-380	-380	-380
Sub-total	(e)	-11,067	-11,447	-11,723	-12,092	-12,347	-12,512	-12,720	-12,882	-13,070	-13,259	-13,464	-13,679	-13,898	-14,130	-14,365	-14,603	-14,844	-15,081
Demand Side Management & Other Measures																			
SMI Theft Reduction		27	27	27	27	27	27	27	27	27	27	27	27	27	27	27	27	27	27
2016 DSM Plan F15 and F16 savings		266	268	259	252	261	261	258	256	252	231	212	210	203	195	191	190	187	185
Sub-total	(f)	293	295	286	279	288	288	285	283	279	258	239	237	230	222	218	217	214	212
		F2017	**F2018**	**F2019**	**F2020**	**F2021**	**F2022**	**F2023**	**F2024**	**F2025**	**F2026**	**F2027**	**F2028**	**F2029**	**F2030**	**F2031**	**F2032**	**F2033**	**F2034**
Surplus / Deficit	(g) = d + e + f	**526**	**160**	**(173)**	**(592)**	**(856)**	**(1,031)**	**(1,489)**	**(1,693)**	**(1,356)**	**(1,603)**	**(1,826)**	**(2,084)**	**(2,342)**	**(2,698)**	**(2,581)**	**(2,822)**	**(3,072)**	**(3,332)**
Low Load Forecast Surplus / Deficit		1,072	962	872	658	529	468	55	(117)	279	91	(59)	(281)	(475)	(816)	(599)	(792)	(939)	(1,198)
High Load Forecast Surplus / Deficit		(22)	(673)	(1,301)	(1,970)	(2,398)	(2,644)	(3,181)	(3,428)	(3,200)	(3,518)	(3,799)	(4,115)	(4,433)	(4,853)	(4,770)	(5,096)	(5,442)	(5,770)

Table 3 Energy LRB After Planned Resources

				Operating	Planning														
(GWh)		F2017	F2018	F2019	F2020	F2021	F2022	F2023	F2024	F2025	F2026	F2027	F2028	F2029	F2030	F2031	F2032	F2033	F2034
Existing and Committed Heritage Resources		46,935	46,054	46,228	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
Site-C									388	4,435	5,100	5,100	5,100	5,100	5,100	5,100	5,100	5,100	5,100
Sub-total	(a)	46,935	46,054	46,228	48,671	48,671	48,671	48,671	49,059	53,106	53,771	53,771	53,771	53,771	53,771	53,771	53,771	53,771	53,771
Existing and Committed IPP Resources	(b)	13,919	14,735	14,208	16,205	15,948	15,359	13,225	12,688	12,319	11,928	11,818	11,500	10,963	10,187	9,723	9,654	9,608	9,447
Future Supply-Side Resources																			
IPP Renewals		84	241	569	683	811	1,108	3,168	3,586	3,850	4,171	4,255	4,442	4,850	5,583	6,048	6,099	6,141	6,302
Standing Offer Program		75	168	279	389	500	611	721	832	943	1,053	1,164	1,275	1,385	1,496	1,607	1,717	1,828	1,939
North Coast Capacity Additions		0	0	0	0	0	154	154	154	154	154	154	154	154	154	154	154	154	154
Sub-total	(c)	159	409	848	1,072	1,311	1,873	4,043	4,572	4,947	5,378	5,573	5,871	6,389	7,233	7,808	7,970	8,123	8,395
Total Supply	(d) = a + b + c	61,012	61,198	61,284	65,948	65,930	65,903	65,940	66,320	70,372	71,077	71,162	71,142	71,123	71,192	71,302	71,396	71,503	71,613
Demand - Integrated System Total Gross Requirements																			
2015 Oct Mid Load Forecast Before DSM*		-60,231	-61,866	-63,832	-65,432	-66,676	-67,843	-68,850	-69,650	-70,420	-71,440	-72,288	-73,316	-74,277	-75,292	-76,381	-77,515	-78,441	-79,350
Expected LNG Load		-289	-355	-518	-2,020	-2,544	-2,570	-3,000	-3,000	-3,000	-3,000	-3,000	-3,000	-3,000	-3,000	-3,000	-3,000	-3,000	-3,000
Sub-total	(e)	-60,520	-62,221	-64,350	-67,452	-69,220	-70,413	-71,850	-72,650	-73,420	-74,440	-75,288	-76,316	-77,277	-78,292	-79,381	-80,515	-81,441	-82,350
Demand Side Management & Other Measures																			
SMI Theft Reduction		193	193	193	193	193	193	193	193	193	193	193	193	193	193	193	193	193	193
Voltage and VAR Optimization		111	200	220	237	268	289	302	307	312	316	334	339	344	348	353	358	363	369
2016 DSM Plan F15 and F16 savings		1,343	1,390	1,367	1,335	1,357	1,383	1,391	1,401	1,397	1,242	1,107	1,108	1,072	1,021	1,003	1,018	1,016	1,005
2016 DSM Plan F2017+ savings		680	1,289	1,785	2,448	2,968	3,415	3,814	4,153	4,423	4,853	5,203	5,399	5,626	5,869	6,082	6,178	6,095	6,077
Sub-total	(f)	2,328	3,072	3,564	4,212	4,786	5,279	5,701	6,054	6,325	6,604	6,837	7,039	7,235	7,431	7,632	7,746	7,667	7,643
		F2017	**F2018**	**F2019**	**F2020**	**F2021**	**F2022**	**F2023**	**F2024**	**F2025**	**F2026**	**F2027**	**F2028**	**F2029**	**F2030**	**F2031**	**F2032**	**F2033**	**F2034**
Surplus / Deficit	(g) = d + e + f	**2,819**	**2,048**	**498**	**2,709**	**1,496**	**769**	**(209)**	**(276)**	**3,277**	**3,241**	**2,711**	**1,866**	**1,082**	**331**	**(447)**	**(1,373)**	**(2,272)**	**(3,094)**
Small Gap Surplus / Deficit		5,611	6,137	5,903	9,251	8,743	8,654	7,917	8,001	11,833	12,102	11,931	11,260	10,782	10,050	9,784	9,082	8,698	7,829
Large Gap Surplus / Deficit		*(341)*	*(2,682)*	*(5,926)*	*(5,217)*	*(7,388)*	*(8,606)*	*(10,090)*	*(10,429)*	*(7,484)*	*(7,942)*	*(8,780)*	*(9,947)*	*(11,045)*	*(12,128)*	*(13,078)*	*(14,456)*	*(15,808)*	*(16,927)*

Table 4 **Peak Capacity LRB After Planned Resources**

				Operating	Planning														
(MW)		**F2017**	**F2018**	**F2019**	**F2020**	**F2021**	**F2022**	**F2023**	**F2024**	**F2025**	**F2026**	**F2027**	**F2028**	**F2029**	**F2030**	**F2031**	**F2032**	**F2033**	**F2034**
Existing and Committed Heritage Resources		11,419	11,457	11,463	11,463	11,463	11,527	11,527	11,527	11,113	11,113	11,113	11,113	11,113	11,113	11,527	11,527	11,527	11,527
Site-C									0	1,100	1,100	1,100	1,100	1,100	1,100	1,100	1,100	1,100	1,100
Sub-total	(a)	11,419	11,457	11,463	11,463	11,463	11,527	11,527	11,527	12,213	12,213	12,213	12,213	12,213	12,213	12,627	12,627	12,627	12,627
Existing and Committed IPP Resources	(b)	1,688	1,664	1,601	1,552	1,530	1,453	1,165	1,121	1,059	1,017	1,017	968	930	798	798	794	788	764
Future Supply-Side Resources																			
IPP Renewals		10	23	55	79	92	135	419	436	446	480	480	508	532	665	665	668	674	699
Standing Offer Program		5	11	19	26	34	41	49	56	63	71	78	86	93	101	108	116	123	130
North Coast Capacity Additions							100	100	100	100	100	100	100	100	100	100	100	100	100
Revolstoke 6											488	488	488	488	488	488	488	488	488
Sub-total	(c)	15	35	73	106	126	276	568	592	609	1,139	1,146	1,182	1,213	1,353	1,361	1,372	1,385	1,417
Total Supply	(d) = a + b + c	13,122	13,155	13,137	13,120	13,119	13,256	13,259	13,240	13,881	14,369	14,376	14,362	14,357	14,364	14,785	14,792	14,800	14,807
14% of Supply Requiring Reserves	(e)	-1,809	-1,813	-1,811	-1,808	-1,808	-1,826	-1,825	-1,825	-1,922	-1,990	-1,991	-1,989	-1,988	-1,989	-2,048	-2,049	-2,050	-2,051
Effective Load Carrying Capability	(f) = d + e	11,313	11,342	11,327	11,312	11,311	11,430	11,433	11,415	11,959	12,379	12,385	12,373	12,369	12,375	12,737	12,743	12,750	12,756
Demand - Integrated System Peak																			
2015 Oct Mid Load Forecast Before DSM*		-11,022	-11,402	-11,628	-11,807	-12,021	-12,186	-12,340	-12,502	-12,690	-12,879	-13,084	-13,299	-13,518	-13,750	-13,985	-14,223	-14,464	-14,701
Expected LNG Load		-45	-45	-95	-285	-326	-326	-380	-380	-380	-380	-380	-380	-380	-380	-380	-380	-380	-380
Sub-total	(g)	-11,067	-11,447	-11,723	-12,092	-12,347	-12,512	-12,720	-12,882	-13,070	-13,259	-13,464	-13,679	-13,898	-14,130	-14,365	-14,603	-14,844	-15,081
Demand Side Management & Other Measures																			
SMI Theft Reduction		27	27	27	27	27	27	27	27	27	27	27	27	27	27	27	27	27	27
Voltage and VAR Optimization		0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
2016 DSM Plan F15 and F16 savings		266	268	259	252	261	261	258	256	252	231	212	210	203	195	191	190	187	185
2016 DSM Plan F2017+ savings		119	224	311	444	550	622	683	732	768	825	871	897	926	956	980	991	982	990
Sub-total	(h)	412	519	598	723	837	910	968	1,015	1,047	1,083	1,110	1,135	1,157	1,177	1,198	1,208	1,196	1,202
		F2017	**F2018**	**F2019**	**F2020**	**F2021**	**F2022**	**F2023**	**F2024**	**F2025**	**F2026**	**F2027**	**F2028**	**F2029**	**F2030**	**F2031**	**F2032**	**F2033**	**F2034**
Surplus / Deficit	(i) = f + g + h	**658**	**414**	**201**	**(58)**	**(199)**	**(172)**	**(318)**	**(452)**	**(64)**	**202**	**31**	**(170)**	**(372)**	**(578)**	**(431)**	**(651)**	**(898)**	**(1,123)**
Small Gap Surplus / Deficit		1,177	1,176	1,194	1,125	1,106	1,232	1,120	1,011	1,450	1,754	1,640	1,463	1,311	1,110	1,349	1,180	1,048	833
Large Gap Surplus / Deficit		83	(459)	(979)	(1,503)	(1,820)	(1,880)	(2,116)	(2,300)	(2,030)	(1,855)	(2,101)	(2,371)	(2,647)	(2,926)	(2,822)	(3,124)	(3,455)	(3,739)