Chapter 9

Recommended Actions
# Table of Contents

<table>
<thead>
<tr>
<th>Section</th>
<th>Description</th>
<th>Page</th>
</tr>
</thead>
<tbody>
<tr>
<td>9.1</td>
<td>Introduction</td>
<td>9-1</td>
</tr>
<tr>
<td>9.1.1</td>
<td>Chapter Structure</td>
<td>9-4</td>
</tr>
<tr>
<td>9.2</td>
<td>Load/Resource Balance</td>
<td>9-6</td>
</tr>
<tr>
<td>9.3</td>
<td>Base and Contingency Planning</td>
<td>9-9</td>
</tr>
<tr>
<td>9.3.1</td>
<td>Base Resource Plan</td>
<td>9-11</td>
</tr>
<tr>
<td>9.3.2</td>
<td>Contingency Planning</td>
<td>9-17</td>
</tr>
<tr>
<td>9.3.2.1</td>
<td>CRP 1</td>
<td>9-21</td>
</tr>
<tr>
<td>9.3.2.2</td>
<td>CRP 2</td>
<td>9-22</td>
</tr>
<tr>
<td>9.3.2.3</td>
<td>CRP 3</td>
<td>9-24</td>
</tr>
<tr>
<td>9.3.3</td>
<td>Transmission Contingency Plans</td>
<td>9-26</td>
</tr>
<tr>
<td>9.4</td>
<td>Recommended Actions</td>
<td>9-26</td>
</tr>
<tr>
<td>9.4.1</td>
<td>Conserve More</td>
<td>9-27</td>
</tr>
<tr>
<td>9.4.1.1</td>
<td>Action 1. Pursue DSM Option</td>
<td>9-27</td>
</tr>
<tr>
<td>9.4.1.2</td>
<td>Action 2. Advance DSM Options 4 &amp; 5</td>
<td>9-32</td>
</tr>
<tr>
<td>9.4.1.3</td>
<td>Action 3. Pursue DSM Capacity Options</td>
<td>9-34</td>
</tr>
<tr>
<td>9.4.1.4</td>
<td>Future Approval Process</td>
<td>9-36</td>
</tr>
<tr>
<td>9.4.2</td>
<td>Build and Reinvest More</td>
<td>9-37</td>
</tr>
<tr>
<td>9.4.2.1</td>
<td>Action 4. Continue to Pursue Site C</td>
<td>9-37</td>
</tr>
<tr>
<td>9.4.2.2</td>
<td>Action 5. Develop Revelstoke Unit 6</td>
<td>9-42</td>
</tr>
<tr>
<td>9.4.2.3</td>
<td>Action 6. Bridging Capacity from Existing Resources</td>
<td>9-46</td>
</tr>
<tr>
<td>9.4.2.4</td>
<td>Action 7. Investigate and Advance Additional Resource Smart Projects</td>
<td>9-49</td>
</tr>
<tr>
<td>9.4.2.5</td>
<td>Action 8. North Coast Transmission Upgrade</td>
<td>9-51</td>
</tr>
<tr>
<td>9.4.3</td>
<td>Buy More</td>
<td>9-54</td>
</tr>
<tr>
<td>9.4.3.1</td>
<td>Action 9. Develop 2,000 GWh/year Clean Procurement Option</td>
<td>9-54</td>
</tr>
<tr>
<td>9.4.3.2</td>
<td>Action 10. Explore Pumped Storage</td>
<td>9-59</td>
</tr>
<tr>
<td>9.4.4</td>
<td>Prepare for Potentially Greater Demand</td>
<td>9-63</td>
</tr>
<tr>
<td>9.4.4.1</td>
<td>Action 11. New Transmission Infrastructure from Peace River to North Coast</td>
<td>9-63</td>
</tr>
<tr>
<td>9.4.4.2</td>
<td>Action 12. Develop Future Acquisitions for LNG3</td>
<td>9-67</td>
</tr>
<tr>
<td>9.4.4.3</td>
<td>Action 13. Natural Gas-fired Generation to Provide Contingency Capacity Options</td>
<td>9-71</td>
</tr>
</tbody>
</table>
9.4.4.4 Action 14. Monitor Fort Nelson/Horn River Basin Load and Supply .............................................. 9-75
9.5 Additional IRP Recommendations .......................................................... 9-78
9.5.1 Province-Wide Electrification/Greenhouse Gas Reduction Initiatives ................................................................. 9-78
9.5.2 Export Market Analysis ........................................................................ 9-79
9.5.3 Transmission Planning for Generation Clusters ..................................... 9-80
9.5.4 Geothermal ......................................................................................... 9-81
9.6 Summary of IRP Recommended Actions Aligned with Clean Energy Act Objectives .................................................. 9-82

List of Figures

Figure 9-1 Energy Load/Resource Balance .......................................................... 9-6
Figure 9-2 Capacity Load/Resource Balance ..................................................... 9-8
Figure 9-3 Energy Load/Resource Balance: Base Resource Plan .................... 9-13
Figure 9-4 Capacity Load/Resource Balance: Base Resource Plan ................ 9-14
Figure 9-5 Energy Load/Resource Balance: Base Resource Plan without Initial LNG .......................................................... 9-15
Figure 9-6 Capacity Load/Resource Balance: Base Resource Plan without Initial LNG .......................................................... 9-16
Figure 9-7 Energy Load/Resource Balance: CRP 1 ........................................ 9-21
Figure 9-8 Capacity Load/Resource Balance: CRP 1 ...................................... 9-22
Figure 9-9 Energy Load/Resource Balance: CRP 2 ........................................ 9-23
Figure 9-10 Capacity Load/Resource Balance: CRP 2 .................................... 9-24
Figure 9-11 Energy Load/Resource Balance: CRP 3 ...................................... 9-25
Figure 9-12 Capacity Load/Resource Balance: CRP 3 .................................... 9-26

List of Tables

Table 9-1 IRP Recommended Action Description ............................................. 9-2
Table 9-2 Action Plan Alignment with BRP Scenarios ...................................... 9-4
Table 9-3 Energy Surplus/Deficit Summary (GWh/year) .................................. 9-7
Table 9-4 Capacity Surplus/Deficit Summary (MW) ....................................... 9-8
Table 9-5 IRP Risks and Rationale ................................................................. 9-10
Table 9-6 IRP Recommended Actions Related to Preparing for Potentially Greater Demand .................................................. 9-18
Table 9-7  Contingency Resource Plan Shortfall Risks................................. 9-19
Table 9-8  Main Assumptions and Rationale for BRP and CRPs.................. 9-20
Table 9-9  Utility Cost of Energy-Focused DSM ($ million) ......................... 9-27
Table 9-10 Energy-Focused DSM: Cumulative Energy Savings since F2012 at Customer Meter in F2021 (GWh) (mid)................................. 9-28
Table 9-11 Energy-Focused DSM: Cumulative Associated Capacity Savings since F2012 in F2021 at Customer Meter (MW) (mid)................................................................. 9-28
Table 9-12 Capacity-Focused DSM: Cumulative Capacity Savings since F2012 at Customer Meter in F2021 (MW) (mid) ......................... 9-35
Table 9-13 Transmission Reinforcement Earliest Required In-Service Date and Direct Costs................................................................. 9-52
Table 9-14 Transmission Reinforcement Earliest Required In-Service Date and Direct Costs................................................................. 9-65
Table 9-15 IRP Recommended Actions.................................................... 9-82
9.1 Introduction

This chapter presents BC Hydro’s 10-year Action Plan with 14 Recommended Actions needed to fill the load/resource gap discussed in Chapter 2 and ensure an adequate supply of reliable cost-effective electricity in the future for BC Hydro’s customers. These actions are based on BC Hydro’s analysis and results described in Chapters 1 through 7 as well as feedback from First Nations, the public and stakeholders as discussed in Chapter 8. The development of these Recommended Actions is guided by the 2010 Clean Energy Act (CEA) and its associated British Columbia’s energy objectives (“CEA objectives”).

The IRP proposes these Recommended Actions to ensure that BC Hydro can reliably supply its customers’ load requirements under both expected (or base) conditions and contingency conditions. The Recommended Actions will be committed to with approval of the IRP and taken over the next ten years.

The Recommended Actions describe the next steps to advance the specific project or initiative, including the costs or expenditures associated with undertaking the steps. The projects proposed in the Recommended Actions will typically require additional consultation requirements and independent review or approval processes; as such, the IRP provides the long-term planning context for future regulatory processes or applications.

Table 9-1 provides an overview of the Recommended Actions.
## Table 9-1 IRP Recommended Action Description

<table>
<thead>
<tr>
<th>Category</th>
<th>IRP Recommended Action</th>
</tr>
</thead>
<tbody>
<tr>
<td>Conserve More</td>
<td>1. Pursue DSM Option 3 Increase energy savings target to 9,800 GWh/year by F2021 (1,000 GWh/year more than the current plan) through conservation and efficiency programs, incentives and regulations.</td>
</tr>
<tr>
<td></td>
<td>2. Advance DSM Options 4 &amp; 5 Explore more codes, standards, and rate options for savings beyond the 9,800 GWh/year target. This action supports the recently introduced Bill 32 (<em>Energy and Water Efficiency Act</em>).</td>
</tr>
<tr>
<td></td>
<td>3. Pursue DSM Capacity Options Pursue voluntary capacity-focused conservation programs that encourage residential, commercial and industrial customers to reduce energy consumption during peak periods.</td>
</tr>
<tr>
<td>Build &amp; Reinvest More</td>
<td>4. Continue to Pursue 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, subject to environmental certification and fulfilling of the Crown’s duty to consult, and where appropriate, accommodate Aboriginal groups.</td>
</tr>
<tr>
<td></td>
<td>5. Develop Revelstoke Unit 6 Begin work to allow the sixth generating unit at Revelstoke Generating Station to be built by F2019, adding 500 MW of peak capacity to the BC Hydro system.</td>
</tr>
<tr>
<td></td>
<td>6. Pursue Bridging Capacity from Existing Resources Fill the short-term peak capacity gap from F2016 to F2021 with a combination of market purchases first, power from the Columbia River Treaty second, and extending the existing back-up use of Burrard Thermal Generating Station (<em>Burrard</em>), if required and as authorized by regulation.</td>
</tr>
<tr>
<td></td>
<td>7. Investigate and Advance Additional Resource Smart Projects Continue to investigate and advance cost-effective Resource Smart projects to utilize the remaining, untapped capacity within BC Hydro’s existing hydroelectric system.</td>
</tr>
<tr>
<td></td>
<td>8. Upgrade Existing WSN to SKA 500 kV Transmission Reinforce the existing 500 kV line from Prince George (Williston Substation (<em>WSN</em>)) to Terrace (Skeena Substation (<em>SKA</em>)) to meet new demand on the North Coast.</td>
</tr>
<tr>
<td>Category</td>
<td>IRP Recommended Action</td>
</tr>
<tr>
<td>-------------------------------</td>
<td>-----------------------------------------------------------------------------------------------------------</td>
</tr>
<tr>
<td><strong>Buy More</strong></td>
<td>9. Develop 2,000 GWh/year Clean Procurement Option: Develop energy procurement options to acquire up to 2,000 GWh/year from clean energy producers for projects that would come into service in the F2017 to F2019 time period.</td>
</tr>
<tr>
<td></td>
<td>10. Explore Pumped Storage: Explore pumped storage capacity options to reduce the lead time to in-service dates and to develop an understanding of where and how to site such future resources in the province, should they be needed.</td>
</tr>
<tr>
<td><strong>Prepare for Potentially Greater Demand</strong></td>
<td>11. Assess New Transmission Infrastructure from Peace River to North Coast: Undertake work to maintain the earliest in-service date for a new 500 kV transmission line from Prince George to Terrace and Kitimat, and from the Peace River region to Prince George.</td>
</tr>
<tr>
<td></td>
<td>12. Develop Future Clean Procurement Options for LNG3: Develop procurement options for additional clean energy resources, backed-up by gas-fired generation — located either in the North Coast or both in the North Coast and across B.C. — for energy that could be delivered in the F2020-F2021 timeframe, should it be needed.</td>
</tr>
<tr>
<td></td>
<td>13. Explore Gas-Fired Contingency Capacity Options: Explore natural gas-fired generation options to reduce the lead time to in-service dates and to develop an understanding of where and how to site such future resources in the province, should they be needed.</td>
</tr>
<tr>
<td></td>
<td>14. Monitor Fort Nelson/Horn River Basin Load and Supply: Continue to monitor the Northeast natural gas industry and undertake studies to keep open electricity supply options, including transmission connection to the integrated system and local gas-fired generation.</td>
</tr>
</tbody>
</table>

1 A number of the Recommended Actions are contingent on liquefied natural gas (LNG) project load commitment. Table 9-2 shows which Recommended Actions are driven by the Initial LNG load commitment and which actions are maintaining options to supply LNG3. A number of the Recommended Actions are needed for contingency plans with or without LNG load commitments.
# Chapter 9 - Recommended Actions

## Table 9-2  Action Plan Alignment with BRP Scenarios

<table>
<thead>
<tr>
<th>Strategy</th>
<th>Recommended Action</th>
<th>Action Plan without Initial LNG</th>
<th>Action Plan with Initial LNG</th>
<th>Action Plan with Initial LNG plus LNG3</th>
</tr>
</thead>
<tbody>
<tr>
<td><strong>Conserve More</strong></td>
<td>1. Pursue DSM Option 3</td>
<td></td>
<td>✓</td>
<td>*</td>
</tr>
<tr>
<td></td>
<td>2. Advance DSM Options 4 &amp; 5</td>
<td>✓</td>
<td></td>
<td></td>
</tr>
<tr>
<td></td>
<td>3. Pursue DSM Capacity Options</td>
<td>✓</td>
<td></td>
<td></td>
</tr>
<tr>
<td><strong>Build &amp; Reinvest More</strong></td>
<td>4. Continue to Pursue Site C</td>
<td>✓</td>
<td></td>
<td></td>
</tr>
<tr>
<td></td>
<td>5. Develop Revelstoke Unit 6</td>
<td>✓</td>
<td></td>
<td></td>
</tr>
<tr>
<td></td>
<td>6. Pursue Bridging Capacity from Existing Resources</td>
<td>✓</td>
<td></td>
<td></td>
</tr>
<tr>
<td></td>
<td>7. Investigate and Advance Additional Resource Smart Projects</td>
<td></td>
<td>✓</td>
<td></td>
</tr>
<tr>
<td></td>
<td>8. Upgrade Existing WSN to SKA 500 kV Transmission</td>
<td></td>
<td>✓**</td>
<td></td>
</tr>
<tr>
<td><strong>Buy More</strong></td>
<td>9. Develop 2,000 GWh/year Clean Procurement Option</td>
<td></td>
<td>✓</td>
<td></td>
</tr>
<tr>
<td></td>
<td>10. Explore Pumped Storage</td>
<td>✓</td>
<td></td>
<td></td>
</tr>
<tr>
<td><strong>Prepare for Potentially Greater Demand</strong></td>
<td>11. Assess New Transmission Infrastructure from Peace River to North Coast</td>
<td></td>
<td>✓</td>
<td></td>
</tr>
<tr>
<td></td>
<td>12. Develop Future Clean Procurement Options for LNG3</td>
<td></td>
<td>✓</td>
<td></td>
</tr>
<tr>
<td></td>
<td>13. Explore Gas-Fired Contingency Capacity Options</td>
<td>✓</td>
<td></td>
<td></td>
</tr>
<tr>
<td></td>
<td>14. Monitor Fort Nelson/Horn River Basin Load and Supply</td>
<td>✓</td>
<td></td>
<td></td>
</tr>
</tbody>
</table>

* If Initial LNG is delayed, BC Hydro may consider reverting back to current DSM targets.

** If Initial LNG is delayed, BC Hydro would evaluate other load growth in the North Coast region to assess whether the upgrades are still required.

## 9.1.1 Chapter Structure

The remainder of this Chapter is laid out as follows:
• Section 9.2 restates BC Hydro’s need for new energy and capacity.

• Section 9.3 provides (1) BC Hydro’s 20-year Base Resource Plan (BRP) of actions to meet the mid gap; (2) contingency actions to address load growth uncertainty and resource uncertainty that result in specific Contingency Resource Plans (CRP) that inform transmission supply contingency plans; and (3) Transmission Contingency Plans (TCP) to manage uncertainties associated with the delivery of transmission resources.

• Section 9.4 provides the details for the 14 Recommended Actions that BC Hydro proposes to carry out to address the load/resource gap described in section 2.4, including the justification, relevant steps for implementation or execution, risk mitigation measures, as well as proposed future approval process with respect to each Recommended Action.

• Section 9.5 discusses additional IRP recommendations that enable BC Hydro to fully respond to the policy framework underpinned by the CEA. These activities include:

  ▶ Support potential future B.C. Government policy direction on province-wide general electrification through continued analysis and study;

  ▶ Continue to monitor developments in export markets to assess whether there are opportunities suitable for B.C. clean and renewable resources;

  ▶ Consider the need for transmission facility advancement for generation clusters during acquisition processes when projects in cluster regions are being bid; and

  ▶ Explore the opportunities for geothermal as a viable low cost, high capacity generation resource in B.C.
- Section 9.6 provides a summary on how the recommendations in the Action Plan respond to the self-sufficiency requirement and the other 15 CEA energy objectives.

9.2 Load/Resource Balance

As detailed in Chapter 2, the need for new resources under the expected load and current Demand-Side Measures (DSM) plan is shown with and without the load from the Initial LNG. Figure 9-1 and Table 9-3 restate the need for new energy resources and Figure 9-2 and Table 9-4 restate the need for new capacity resources. In addition, these figures show the increased need for new resources with LNG3 and the High Mining Scenario presented in Chapter 2.

![Energy Load/Resource Balance](image-url)
Table 9-3

<table>
<thead>
<tr>
<th>Load</th>
<th>F2017</th>
<th>F2021</th>
<th>F2031</th>
</tr>
</thead>
<tbody>
<tr>
<td>Mid Load After Current DSM Target</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>without the Initial LNG</td>
<td>3,039</td>
<td>346</td>
<td>-7,197</td>
</tr>
<tr>
<td>Mid Load After Current DSM Target</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>with LNG3</td>
<td>-761</td>
<td>-4,935</td>
<td>-12,478</td>
</tr>
<tr>
<td>Mid Load After Current DSM Target</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>with LNG3 and High Mining</td>
<td>-2,292</td>
<td>-16,503</td>
<td>-26,996</td>
</tr>
</tbody>
</table>

The energy load/resource balance (LRB) in Figure 9-1 shows that prior to the Initial LNG load, BC Hydro will have sufficient energy until F2022 (approximately the time that Site C would be available), largely due to the change to average water planning criteria. With the Initial LNG load, the need for new resources would be advanced to F2017. Additional load growth beyond the Initial LNG would require additional resources.

In summary, with the change to average water criteria and without LNG loads, BC Hydro likely has enough existing and committed energy resources to get through to the Site C in-service date of F2021. Significant volumes of energy will need to be procured to serve LNG loads, ranging from 2,000 GWh/year in F2017 for the Initial LNG projects, to an incremental 12,800 GWh/year in F2019 and F2020 for the third.
The Capacity LRB in Figure 9-2 shows that BC Hydro is short of capacity (about 200 MW) beginning in F2017 prior to the Initial LNG load. With the Initial LNG load, the capacity shortfall increases by approximately 700 MW.
9.3 Base and Contingency Planning

As discussed in Chapters 5 and 6, there are a number of uncertainties that BC Hydro considers in its resource planning and analysis. The uncertainties that result in major risks are managed either by: (1) selecting actions that avoid or minimize the risks; (2) are consistent with good utility practice and the British Columbia Utilities Commission (BCUC) Resource Planning Guidelines; or (3) developing additional actions that seek to mitigate the major risks inherent in the actions selected. Hence, BC Hydro manages the risks associated with its resource plans in one of the following manners:

1. Undertake actions in the BRP that minimize exposure to major risks;
2. Develop additional actions for contingency plans that ensure that alternative sources of supply are available if the risks materialize or additional loads develop;
3. Develop CRPs based upon the Recommended Actions and risks for the purposes of establishing contingency transmission resources for alternative manners in which the province might develop; and
4. Develop TCPs for the major transmission shortage risks associated with the BRP.

BC Hydro has concluded that the following major risks are critical to determining BC Hydro’s Recommended Actions with respect to the need for new generation and transmission resources:
Table 9-5: IRP Risks and Rationale

<table>
<thead>
<tr>
<th>Risk</th>
<th>Rationale</th>
</tr>
</thead>
<tbody>
<tr>
<td>BRP Risks</td>
<td>LNG Load Forecast Uncertainty</td>
</tr>
<tr>
<td></td>
<td>• BC Hydro’s actions with respect to the Initial LNG include increasing reliance on bridging capacity in the near term, pursuing DSM Option 3 and pursuing a 2,000 GWh/year procurement option. Pursuing these actions, while maintaining optionality will not require significant expenditures until the Initial LNG load is committed, and LNG proponents will contribute to covering these expenditures.</td>
</tr>
<tr>
<td>Market Price</td>
<td></td>
</tr>
<tr>
<td></td>
<td>• The move to planning to average water conditions instead of critical water conditions means that BC Hydro will be in a more balanced market position year over year, i.e., BC Hydro is not unduly dependent on buying from or selling to the electricity market.</td>
</tr>
<tr>
<td></td>
<td>• Pursuing actions like a 2,000 GWh/year procurement avoids potential energy surplus that would otherwise be created once Site C comes online or if DSM delivers more than planned. In addition, this provides some potential short-term bridging reliance on the electricity market at low market prices to benefit ratepayers.</td>
</tr>
<tr>
<td>GHG Price</td>
<td></td>
</tr>
<tr>
<td></td>
<td>• BC Hydro’s plan to pursue significant DSM, to build Site C and acquire IPP clean energy to meet the 93% clean objective in the CEA avoids further exposure to GHG offset policies and prices by reducing the need for non-clean resources like natural gas thermal.</td>
</tr>
<tr>
<td></td>
<td>• BC Hydro has not identified any immediate actions with respect to general electrification. BC Hydro will continue to monitor policy developments that support electrification.</td>
</tr>
<tr>
<td>REC Price</td>
<td></td>
</tr>
<tr>
<td></td>
<td>• The variability of Renewable Energy Certificates (REC) prices did not have a significant impact on the Recommended Actions on the level of DSM and acquisitions to meet BC Hydro’s domestic load.</td>
</tr>
<tr>
<td></td>
<td>• BC Hydro’s export analysis reinforces BC Hydro’s strategy to avoid taking on REC price risk for a future opportunity that has not yet been proven.</td>
</tr>
<tr>
<td>Gas Price</td>
<td></td>
</tr>
<tr>
<td></td>
<td>• BC Hydro’s actions to concurrently pursue DSM Option 3 and clean IPP resources and preserve gas for contingency capacity needs avoids further exposure to natural gas price fluctuations.</td>
</tr>
<tr>
<td>IPP Deliverability Risk</td>
<td></td>
</tr>
<tr>
<td></td>
<td>• BC Hydro’s action to pursue a higher DSM target (Option 3) considers the potential for IPP attrition.</td>
</tr>
</tbody>
</table>
### Chapter 9 - Recommended Actions

<table>
<thead>
<tr>
<th>Risk</th>
<th>Rationale</th>
</tr>
</thead>
<tbody>
<tr>
<td><strong>CRP Risks</strong></td>
<td></td>
</tr>
<tr>
<td>General Load Forecast Uncertainty</td>
<td>• BC Hydro’s plan to develop gas-fired contingency options is intended to respond to potential capacity shortfalls. BC Hydro is planning to manage contingency energy shortfalls by undertaking shorter lead time acquisition processes; adjusting DSM programs timing and rate of delivery of energy savings; and in the case of short-term shortfalls rely on market energy acquisitions.</td>
</tr>
<tr>
<td><strong>DSM Deliverability Risk</strong></td>
<td></td>
</tr>
<tr>
<td></td>
<td>• Undertaking actions on DSM Options 4 and 5 helps to reduce DSM deliverability risk for Option 3 because if Option 3 does not deliver there may be additional savings from Options 4 and 5 that can be drawn upon.</td>
</tr>
<tr>
<td></td>
<td>BC Hydro’s plan to develop gas-fired contingency options is intended to respond to potential capacity shortfalls. BC Hydro is planning to manage contingency energy shortfalls by undertaking shorter lead time acquisition processes; adjusting DSM programs timing and rate of delivery of energy savings; and in the case of short-term shortfalls, rely on market energy acquisitions.</td>
</tr>
<tr>
<td><strong>Additional North Coast LNG and Mining Load (LNG3 + High Mining Scenario)</strong></td>
<td></td>
</tr>
<tr>
<td></td>
<td>• BC Hydro’s plan to develop flexible gas-fired contingency options, future clean procurement options and associated transmission for these loads are intended to respond to potential capacity and energy shortfalls that could arise if these loads materialize.</td>
</tr>
</tbody>
</table>

#### 9.3.1 Base Resource Plan

BC Hydro’s BRP is a 20-year view of the resulting portfolio of resources needed to fill the load/resource gap. In general, the need in the first ten years is provided by the Recommended Actions. The need in the remaining ten years is met by the continuance of the same strategies used to develop the Recommended Actions with the underlying purpose of building a broader inventory of reliable resources. A key purpose of translating the Recommended Actions into a 20-year view is for transmission planning purposes, which is discussed later in this section.

The actions identified in the BRP allow BC Hydro to meet its current and future customers’ electricity needs on a reliable and cost-effective basis. This BRP responds to the B.C. Government’s CEA and the legislative requirements listed in section 9.6.
The main assumptions in preparing the BRP are as follows:

- 2011 mid Load Forecast with Initial LNG;
- DSM Option 3 (mid);
- Bridging capacity with market purchases, Canadian Entitlement (CE) and, if necessary; Burrard;
- Site C in its earliest in-service date;
- Revelstoke Unit 6 at its earliest in-service date;
- 2,000 GWh/year clean procurement in F2017;
- Clean IPP energy to fill remaining energy gap after Site C; and
- Pumped storage to fill remaining capacity gap after Site C.

The BRP is shown in the following graphs for energy and capacity respectively\(^1\).

\(^1\) Graphs in the following sub-sections show a magnified y-axis to better identify the timing, volume and nature of resource additions that form the BRP and CRPs. For energy graphs, the y-axis starts at 50,000 GWh/year and for capacity graphs the y-axis starts at 10,000 MW.
Figure 9-3  Energy Load/Resource Balance: Base Resource Plan

<table>
<thead>
<tr>
<th>Fiscal Year (year ending March 31)</th>
<th>Firm Energy Capability (GWh)</th>
</tr>
</thead>
<tbody>
<tr>
<td>F2012</td>
<td>50,000</td>
</tr>
<tr>
<td>F2013</td>
<td>55,000</td>
</tr>
<tr>
<td>F2014</td>
<td>60,000</td>
</tr>
<tr>
<td>F2015</td>
<td>65,000</td>
</tr>
<tr>
<td>F2016</td>
<td>70,000</td>
</tr>
<tr>
<td>F2017</td>
<td>75,000</td>
</tr>
<tr>
<td>F2018</td>
<td>80,000</td>
</tr>
<tr>
<td>F2019</td>
<td>85,000</td>
</tr>
<tr>
<td>F2020</td>
<td>90,000</td>
</tr>
<tr>
<td>F2021</td>
<td>95,000</td>
</tr>
<tr>
<td>F2022</td>
<td>100,000</td>
</tr>
</tbody>
</table>

Operating Planning

Existing and Committed Resources  Planned Resources  Revelstoke Unit 6
Site C  Future Clean IPP Acquisitions  2011 Mid Load Forecast After DSM
BC Hydro also prepared a BRP without the Initial LNG using the same assumptions as the BRP with the Initial LNG. The BRP without the Initial LNG is shown in the following graphs for energy and capacity respectively.
Figure 9-5 Energy Load/Resource Balance: Base Resource Plan without Initial LNG

Fiscal Year (year ending March 31)

- Existing and Committed Resources
- Revelstoke Unit 6
- Planned Resources
- Site C
- Future Clean IPP Acquisitions
- 2011 Mid Load Forecast After DSM without Initial LNG
As mentioned earlier, one of the key purposes of developing a BRP is for transmission planning. As new transmission lines can have longer lead times for development, transmission planners often need to look beyond ten years. Accordingly, the BRP is used to establish future transmission requirements by BC Hydro transmission planners.

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 and as the Initial LNG loads reach key milestones, BC Hydro will submit this BRP as a transmission service request under the OATT tariff. BC Hydro periodically supplies the transmission
planners with the most current BRP as load conditions and supply conditions change. Transmission requests for contingency plans are discussed below.

9.3.2 Contingency Planning

Contingency planning identifies alternative sources of supply that should be available should the BRP not materialize as expected. The aim of the associated actions is to reduce the lead time for supply-side resources being placed in service if the need arises. If the advanced in-service dates are not planned for and not maintained, the contingency plan will be ineffectual.

To minimize the costs of the actions in contingency planning, BC Hydro seeks to maintain in-service dates by moving resources through the Investigation and Definition phases of project development incurring minimal costs and without committing to construction. However, 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 was a high consequence of the shortage, BC Hydro would identify to the BCUC its plan to construct the resource with the appropriate application, initiating final Implementation including approvals.

The following subset of the Recommended Actions shown in Table 9-6 help to prepare system energy and capacity resources for potentially greater demand.
Table 9-6 IRP Recommended Actions Related to Preparing for Potentially Greater Demand

<table>
<thead>
<tr>
<th></th>
<th></th>
<th></th>
<th></th>
</tr>
</thead>
<tbody>
<tr>
<td>2. Advance DSM Options 4 &amp; 5</td>
<td>✓</td>
<td>✗</td>
<td></td>
</tr>
<tr>
<td>3. Pursue DSM Capacity Options</td>
<td>✗</td>
<td>✗</td>
<td></td>
</tr>
<tr>
<td>7. Investigate and Advance Additional Resource Smart Projects</td>
<td></td>
<td>✗</td>
<td></td>
</tr>
<tr>
<td>10. Explore Pumped Storage</td>
<td>✗</td>
<td>✗</td>
<td></td>
</tr>
<tr>
<td>12. Develop Future Clean Procurement Options for LNG3</td>
<td></td>
<td></td>
<td>✓</td>
</tr>
<tr>
<td>13. Explore Gas-Fired Contingency Capacity Options</td>
<td>✗</td>
<td></td>
<td></td>
</tr>
</tbody>
</table>

Similar to the action under the BRP, BC Hydro translates these actions into potential portfolios of resources called CRPs that meet the alternative customer demands and submits those under the OATT as well for the purposes of establishing a queue position for a transmission service request. BC Hydro requires and will request the BCUC’s approval of the CRPs for submission to transmission planning. CRPs are particularly important in light of the typically long lead times for transmission projects. As such, 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.

In developing the CRPs, BC Hydro used both capacity and energy shortfall risks that were identified in section 6.10. Capacity requirements are the primary concern for BC Hydro since capacity is required to meet peak load requirements and maintain system security and reliability. Shortfall risks identified by BC Hydro are shown in Table 9-7.
Table 9-7 Contingency Resource Plan Shortfall Risks

<table>
<thead>
<tr>
<th>Risk</th>
<th>Rationale</th>
</tr>
</thead>
<tbody>
<tr>
<td>General Load Forecast Uncertainty</td>
<td>Peak load and energy requirements can increase as a result of either sustained growth or low temperatures at winter peak.</td>
</tr>
<tr>
<td>DSM Deliverability Risk</td>
<td>The DSM Implementation Plan has a significant range of deliverability risk where the variability is driven by implementation of codes and standards, customer response to programs and rates.</td>
</tr>
<tr>
<td>Additional North Coast LNG and Mining Load</td>
<td>BC Hydro has received interconnection requests for significant volumes of energy and capacity in B.C.’s North Coast. This coupled with the potential correlation between industrial sector growth and general economic growth in the high Load Forecast makes it an important consideration in BC Hydro’s CRPs.</td>
</tr>
<tr>
<td>Total Reduction</td>
<td></td>
</tr>
</tbody>
</table>

<table>
<thead>
<tr>
<th>Risk</th>
<th>Capacity Reduction for CRP Purposes(^2,3) (MW)</th>
<th>Energy Shortfall Risk (GWh/year)</th>
</tr>
</thead>
<tbody>
<tr>
<td>F2017</td>
<td>F2031</td>
<td>F2017</td>
</tr>
<tr>
<td>F2031</td>
<td></td>
<td>F2031</td>
</tr>
<tr>
<td>General Load Forecast Uncertainty</td>
<td>558</td>
<td>1,212</td>
</tr>
<tr>
<td></td>
<td></td>
<td>3,024</td>
</tr>
<tr>
<td></td>
<td></td>
<td>6,630</td>
</tr>
<tr>
<td>DSM Deliverability Risk</td>
<td>363</td>
<td>666</td>
</tr>
<tr>
<td></td>
<td></td>
<td>2,068</td>
</tr>
<tr>
<td></td>
<td></td>
<td>3,945</td>
</tr>
<tr>
<td>Additional North Coast LNG and Mining Load</td>
<td>276</td>
<td>1,898</td>
</tr>
<tr>
<td>(LNG3 + High Mining Scenario)</td>
<td></td>
<td>1,531</td>
</tr>
<tr>
<td></td>
<td></td>
<td>14,518</td>
</tr>
<tr>
<td>Total Reduction</td>
<td>1,197</td>
<td>3,776</td>
</tr>
<tr>
<td></td>
<td></td>
<td>6,623</td>
</tr>
<tr>
<td></td>
<td></td>
<td>25,093</td>
</tr>
</tbody>
</table>

General load forecast uncertainty and DSM deliverability risk are the typical risks examined in the CRPs; however, with the potential large and uncertain loads from LNG and mining, BC Hydro has also examined these additional loads in preparing the CRPs.

---

\(^2\) Section 6.10 discusses the ability of intermittent resources to impact the need for new capacity resources and concludes that they are only able to offset the need minimally.

\(^3\) Additional 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 5B for a further description.
The actions that BC Hydro undertakes as a result of the risks (identified in Table 9-7) are to advance a cost-effective mix of energy, capacity and transmission resources to meet potential needs. The three CRPs described in Table 9-8 are intended to test the potential transmission requirements in response to the risks described in Table 9-7. The BRP assumptions have also been provided for reference.

<table>
<thead>
<tr>
<th>Plan</th>
<th>Rationale</th>
</tr>
</thead>
<tbody>
<tr>
<td>BRP 1</td>
<td>To meet expected loads and 93% clean objective with cost-effective resources.</td>
</tr>
<tr>
<td>CRP 1</td>
<td>To test the transmission impacts of adding LNG3 and high mining in North Coast without Pumped Storage in the Lower Mainland.</td>
</tr>
<tr>
<td>CRP 2</td>
<td>To test the transmission impacts of the high Load Forecast and low DSM deliverability with Gas at Kelly Lake.</td>
</tr>
<tr>
<td>CRP 3</td>
<td>A combination of CRP 1 and CRP 2 to reflect the potential positive correlation between increased industrial activity and increased economic growth in B.C.</td>
</tr>
</tbody>
</table>

In these CRPs, BC Hydro has not relied on pumped storage in the Lower Mainland to meet long-term capacity requirements because local generation in the load centre
does not test the potential for increased transmission requirements to the load
centre if that generation is built somewhere else. As such, for the purpose of the
CRPs, BC Hydro has assumed that gas capacity at Kelly Lake is the marginal
contingency capacity supply. In addition BC Hydro is planning to manage
contingency energy shortfalls by: undertaking shorter lead time acquisition
processes; adjusting DSM programs timing and rate of delivery of energy savings;
and in the case of short term shortfalls, rely on market energy acquisitions.

9.3.2.1 CRP 1

Figure 9-7 and Figure 9-8 demonstrate the energy and capacity LRBs for CRP 1.

Figure 9-7  Energy Load/Resource Balance: CRP 1
9.3.2.2 **CRP 2**

*Figure 9-9* and *Figure 9-10* demonstrate the energy and capacity LRBs for CRP 2.
Figure 9-9 Energy Load/Resource Balance: CRP 2

<table>
<thead>
<tr>
<th>Fiscal Year (year ending March 31)</th>
<th>Firm Energy Capability (GWh)</th>
</tr>
</thead>
<tbody>
<tr>
<td>F2012</td>
<td>50,000</td>
</tr>
<tr>
<td>F2013</td>
<td>55,000</td>
</tr>
<tr>
<td>F2014</td>
<td>60,000</td>
</tr>
<tr>
<td>F2015</td>
<td>65,000</td>
</tr>
<tr>
<td>F2016</td>
<td>70,000</td>
</tr>
<tr>
<td>F2017</td>
<td>75,000</td>
</tr>
<tr>
<td>F2018</td>
<td>80,000</td>
</tr>
<tr>
<td>F2019</td>
<td>85,000</td>
</tr>
<tr>
<td>F2020</td>
<td>90,000</td>
</tr>
<tr>
<td>F2021</td>
<td>95,000</td>
</tr>
<tr>
<td>F2022</td>
<td>100,000</td>
</tr>
</tbody>
</table>

Legend:
- Existing and Committed Resources
- Planned Resources
- Revelstoke Unit 6
- Site C
- Future Clean IPP Acquisitions
- New Gas Capacity at Kelly Lake
- 2011 High Load Forecast After DSM

Operating Planning
Figure 9-10  Capacity Load/Resource Balance: CRP 2

Figure 9-11 and Figure 9-12 demonstrate the energy and capacity LRBs for CRP 3.

9.3.2.3  CRP 3
Figure 9-11  Energy Load/Resource Balance: CRP 3

The diagram illustrates the firm energy capability (GWh) over fiscal years ending March 31, from FY 2012 to FY 2031. It shows the balance between operating and planning energy requirements. The key categories included are:

- Existing and Committed Resources
- Planned Resources
- Revelstoke Unit 6
- Site C
- Future Clean IPP Acquisitions
- New Gas Capacity at Kelly Lake

The graph indicates the projected increase in energy requirements over the fiscal years, with a focus on the energy load forecast for years 2012 to 2031, considering DSM and high mining load impacts.
The detailed BRP and CRP tables and graphs that would be the basis of the OATT submissions provided to transmission planning are shown in Appendix 9B.

9.3.3 Transmission Contingency Plans

The TCPs are intended to address the key transmission shortages that impact BC Hydro’s resource plans. As demonstrated in section 2.5, there do not appear to be any bulk transmission sections that would cause BC Hydro supply concerns over the next 10 years.

9.4 Recommended Actions

This section presents the IRP’s 14 Recommended Actions that BC Hydro proposes to undertake to implement the plan. These Recommended Actions are organized...
based on the four strategic focuses of Conserve More, Build and Reinvest More, Buy More and Prepare for Potentially Greater Need. The justification, execution, risk mitigation and future approvals are addressed for each of the Recommended Actions.

9.4.1 Conserve More

Three key recommendations are made in the area of DSM energy and capacity saving. Section 9.4.1.1 to 9.4.1.3 outlines these recommendations and their respective justification, execution and risk mitigation. Section 9.4.1.4 discusses the future approval process for these Recommended Actions.

9.4.1.1 Action 1. Pursue DSM Option 3

Recommended Action: Increase energy savings target to 9,800 GWh/year by F2021 (1,000 GWh/year more than the current plan) through conservation and efficiency programs, incentives and regulations.

The utility cost of Option 3 over the four-year period of F2014 – F2017 is estimated to be approximately $1.4 billion.

Table 9-9 below summarizes the utility cost of energy-focused DSM.

<table>
<thead>
<tr>
<th>Table 9-9 Utility Cost of Energy-Focused DSM ($ million)</th>
<th>Four years: F2014 to F2017</th>
<th>19 years: F2014 to F2032</th>
</tr>
</thead>
<tbody>
<tr>
<td>Rate Structures Programs</td>
<td>13</td>
<td>61</td>
</tr>
<tr>
<td>Residential</td>
<td>248</td>
<td>1,223</td>
</tr>
<tr>
<td>Commercial</td>
<td>470</td>
<td>3,005</td>
</tr>
<tr>
<td>Industrial</td>
<td>498</td>
<td>2,183</td>
</tr>
<tr>
<td>Sub-total</td>
<td>1,217</td>
<td>6,411</td>
</tr>
<tr>
<td>Supporting Initiatives</td>
<td>144</td>
<td>815</td>
</tr>
<tr>
<td>Total</td>
<td>1,374</td>
<td>7,287</td>
</tr>
</tbody>
</table>
Further details relating to the energy and capacity savings, costs and cost/benefit analysis of the DSM Implementation Plan are provided in Appendix 9A.

Implementation of energy-focused DSM based on Option 3 is forecast to save approximately 8,900 GWh/year and 1,300 MW at customer meters in F2021, resulting in 9,800 GWh/year of energy savings and 1,500 MW of capacity savings in F2021 when transmission and distribution losses are added.

<table>
<thead>
<tr>
<th>Table 9-10</th>
<th>Energy-Focused DSM: Cumulative Energy Savings since F2012 at Customer Meter in F2021 (GWh) (mid)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Codes and Standards</td>
<td>Rate Structures</td>
</tr>
<tr>
<td>Residential</td>
<td>1,540</td>
</tr>
<tr>
<td>Commercial</td>
<td>699</td>
</tr>
<tr>
<td>Industrial</td>
<td>61</td>
</tr>
<tr>
<td>Total</td>
<td>2,301</td>
</tr>
</tbody>
</table>

<table>
<thead>
<tr>
<th>Table 9-11</th>
<th>Energy-Focused DSM: Cumulative Associated Capacity Savings since F2012 in F2021 at Customer Meter (MW) (mid)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Codes and Standards</td>
<td>Rate Structures</td>
</tr>
<tr>
<td>Residential</td>
<td>401</td>
</tr>
<tr>
<td>Commercial</td>
<td>123</td>
</tr>
<tr>
<td>Industrial</td>
<td>7</td>
</tr>
<tr>
<td>Total</td>
<td>531</td>
</tr>
</tbody>
</table>

**Justification**

- **Cost-Effectiveness** – Option 3 would deliver electricity savings at an average unit net cost of less than $10/MWh\(^4\), compared to new electricity supply.

\(^4\) Chapter 6, Figure 6-10. The net DSM costs reflect deemed natural-gas benefits and deemed Non-energy benefits as defined in the December 2011 amended DSM Regulations.
benchmarked at an average cost of $129/MWh.\footnote{5} As shown in Chapter 6, the expected cost of portfolios with Options 3, 4 and 5 are quite close, with Option 4 being the lowest cost option.\footnote{6} However, going beyond Option 3 is not recommended at this time because the small cost advantage is outweighed by the additional deliverability risk associated with Options 4 and 5. Nevertheless, the upside potential of Options 4 and 5 warrants further attention, as discussed in Recommended Action 2. Detailed discussion of the financial/cost factors of the DSM options is provided in section 6.3.4.4. All DSM tools across all sectors in the DSM Implementation Plan (Appendix 9A) have a Total Resource benefit-cost ratio greater than 1.0 (Appendix 9A, Attachment 1, Table 5).

- **Rate Impact** – Despite the fact that Option 3 is expected to result in a higher rate impact compared to Option 2, it is expected to result in lower overall electricity bills, reducing customer electricity bills by $180 million relative to Option 2 over the 20-year life of the IRP. Option 3 is expected to result in a 2 per cent rate increase over Option 2 over a 10-year period to F2021. Section 6.3.4.4 discusses the analysis on differential rate impact of portfolios containing DSM Options 1, 3, 4, and 5 relative to Option 2.

- **Environmental and Economic Development Benefits** – DSM avoids the environmental impacts associated with the construction of new generation facilities. Incremental DSM also provides economic development benefits through the creation and retention of jobs and increased GDP. However, these results are modest and negligible compared to the measures' precision when comparing other options. The comparisons of these benefits across the DSM Options are presented in Table 6-7 in section 6.3.6.

\footnote{5} $129/MWh is BC Hydro’s current reference energy price based on levelized UEC for the Clean Power Call firm energy price (adjusted for delivery to the Lower Mainland and for transmission losses and other Clean Power Call-related adjustments).

\footnote{6} Chapter 6, Figure 6-11.
Chapter 9 - Recommended Actions

- **Comprehensive and Flexibility** – Option 3 provides a comprehensive portfolio of DSM measures with a broad offering to all customer groups that are designed to complement one another and capture synergies. They are flexible and can be changed over time in response to new information, such as new information on codes and standards, in order to optimize performance and ensure DSM savings targets are achieved.

- **Policy Alignment** – Option 3 aligns with several CEA objectives, as discussed in section 9.6. A key CEA objective for DSM is the objective to reduce the expected increase in demand by 66 per cent by 2020 (CEA objective 2(b)). While Option 3 achieves 78 per cent reduction in the expected increase in demand before the consideration of the Initial LNG load is included and 58 per cent after the Initial LNG is included, Option 3 represents all the cost-effective DSM that BC Hydro can rely upon at this time.

The work undertaken to implement Option 3 will also support Bill 32 (*Energy and Water Efficiency Act*). Bill 32 provides a new framework for the development, administration and enforcement of codes and standards. Together with the Pacific Coast Collaborative’s “2012 West Coast Action Plan on Jobs” that seeks to jointly develop energy efficiency upgrades, technologies and standards, Bill 32 (*Energy and Water Efficiency Act*) would create the potential for additional, cost-effective DSM savings.

**Execution**

- Execution of Option 3 requires action on the part of BC Hydro and all levels of government (federal, provincial, municipal and First Nations). The federal and provincial governments are expected to implement codes and standards included in Option 3 with BC Hydro’s support. BC Hydro will also support the implementation of additional codes and standards that develop over time, such
as those may be prescribed under Bill 32 (Energy and Water Efficiency Act). Electricity savings from additional codes and standards will increase the prospect of achieving targeted electricity savings and may allow BC Hydro to reduce DSM implementation costs; and potentially mitigate some of the rate impact. (However, BC Hydro will continue to pursue and rely on Option 3 until sufficient certainty has been achieved to adjust future DSM implementation plans). In addition, BC Hydro plans to continue implementing existing rate structures and to introduce the Small General Service conservation rate structure in F2018.\(^7\) BC Hydro plans to continue implementing its ongoing DSM programs, sector enabling activities and six supporting initiatives. Finally, BC Hydro plans to launch new load displacement programs in the residential and commercial sectors.

Risk Mitigation

BC Hydro’s approach to DSM risk mitigation begins with the identification and assessment of risk and the development of mitigation measures at various stages in the development of DSM plans and initiatives. Mitigation is aimed at two key risks: not achieving targeted DSM energy and capacity savings and DSM costs exceeding plan without a comparable trend in electricity savings. DSM risk mitigation includes:

- **Initiative Design** – DSM initiatives are designed to limit 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 tiered incentive structures that ensure BC Hydro provides an appropriate financial incentive for

---

\(^7\) BC Hydro notes that the provincial government has initiated a review of industrial electricity policy, including industrial rates and rate design.
individual projects and limits the amount needed to achieve DSM electricity savings.

- **Tracking Performance Metrics** – BC Hydro tracks electricity savings and costs on a monthly basis at an initiative level. BC Hydro also tracks leading and lagging performance indicators for each DSM initiative.

- **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. In addition, any additional codes and standards that are developed as a result of Bill 32 (*Energy and Water Efficiency Act*) will be reflected in future Plan adjustments.

As set out in Table 9.2, the final decision to pursue a higher DSM target will be made as the new loads in the current forecast to serve the Initial LNG reach critical milestones. Finally, BC Hydro also manages DSM deliverability risk through CRPs set out in section 9.3.

### 9.4.1.2 Action 2: Advance DSM Options 4 & 5

**Recommended Action:** Explore more codes, standards, and rate options for savings beyond the 9,800 GWh/year target. This action supports the recently introduced Bill 32 (*Energy and Water Efficiency Act*).
This action supports BC Hydro’s preparation for the next IRP and has an approximate cost of $7 million from F2014 to F2017.

Justification

The IRP portfolio analysis presented in Chapter 6 indicated that Options 4 and 5 have the potential to deliver a substantial volume of additional cost-effective electricity savings, over and above Option 3. However, it also found that there is considerable uncertainty regarding the implementation and achievement of these additional electricity savings. A significant aspect of the activities to prove out the savings potential for Options 4 and 5 will be working with the government implementing Bill 32 (Energy and Water Efficiency Act) and the Pacific Coast Collaborative’s “2012 West Coast Action Plan on Jobs”.

BC Hydro concluded that an investment of $7 million over the F2014-F2017 period is warranted to investigate and further develop the range of Option 4/5 tactics in order to reduce uncertainty about their feasibility and/or savings estimates and ultimately inform subsequent IRPs.

Execution

BC Hydro will undertake a range of activities focused on additional rate options (i.e., conservation rate structures), codes and standards and voluntary measures, including:

- Strategy development;
- Market research, studies and opportunity assessments;
- Measure design, including modelling and cost-benefit analysis;
- Customer, trade ally and/or stakeholder engagement; and
- Pilots programs.
Risk Mitigation

BC Hydro will design and manage these activities to achieve the objectives of enhanced certainty at a reasonable cost.

9.4.1.3 Action 3. Pursue DSM Capacity Options

**Recommended Action:** Pursue voluntary capacity-focused conservation programs that encourage residential, commercial and industrial customers to reduce energy consumption during peak periods.

Table 9-11 summarizes the utility cost of capacity-focused DSM.

<table>
<thead>
<tr>
<th>Table 9-11</th>
<th>Utility Cost of Capacity-Focused DSM ($ million)</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>Four years: F2014 to F2017</td>
</tr>
<tr>
<td>Industrial Load Curtailment</td>
<td>64</td>
</tr>
<tr>
<td>Capacity-Focused Programs</td>
<td>80</td>
</tr>
<tr>
<td>Total</td>
<td>143</td>
</tr>
</tbody>
</table>

Capacity-focused DSM has the potential to reduce BC Hydro’s system peak by 475 MW in F2021. The capacity-savings from Capacity-focused DSM are outlined in Table 9-12.
Table 9-12  Capacity-Focused DSM: Cumulative Capacity Savings since F2012 at Customer Meter in F2021 (MW) (mid)

<table>
<thead>
<tr>
<th></th>
<th>F2021</th>
</tr>
</thead>
<tbody>
<tr>
<td>Industrial Load Curtailment</td>
<td>286</td>
</tr>
<tr>
<td>Capacity-Focused Programs</td>
<td></td>
</tr>
<tr>
<td>Residential</td>
<td>99</td>
</tr>
<tr>
<td>Commercial</td>
<td>31</td>
</tr>
<tr>
<td>Industrial</td>
<td>61</td>
</tr>
<tr>
<td>Sub-total</td>
<td>191</td>
</tr>
<tr>
<td>Total</td>
<td>477</td>
</tr>
</tbody>
</table>

Justification

- **Cost-Effectiveness** – The load-resource balance indicates a capacity gap starting in F2017 that persists at different levels over time despite the addition of large increments of generation capacity from Mica Units 5 and 6, Revelstoke Unit 6 and Site C. At that point BC Hydro will have exhausted the supply of relatively low cost and large scale increments of generation capacity and will need to advance a number of long-term capacity options to fill the remaining gap. Two capacity-focused DSM options, Industrial Load Curtailment and Capacity-focused Programs, have the potential to deliver capacity savings over the long-term at an estimated cost of $32/kW-year and $53/kW-year respectively.\(^8\) Please refer to section 6.10.3, Table 6-31 for details regarding other available capacity resources. These costs are lower than gas-fired generation and pumped storage, the marginal capacity resources depending on the timeframe. 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. For this reason, BC Hydro will not yet rely on capacity savings

\(^8\) Includes transmission and distribution losses.
from capacity-focused DSM for resource planning purposes. However, implementation of capacity-focused DSM starting in F2014 is justified based on BC Hydro’s need for capacity resources and the low cost of capacity-focused DSM relative to alternatives. Capacity-focused DSM provides the capacity potential to reduce the need for bridging resources and the likelihood of new gas-fired generation being used in contingency plans. Implementation will provide BC Hydro with information on the cost and impacts of capacity-focused DSM that will inform decisions in future IRPs on whether to rely on capacity-focused DSM as a long-term capacity resource.

- **Environmental Attributes** – If successful, capacity-focused DSM will avoid the need for 475 MW of generation and bulk transmission capacity, resulting in a lower environmental footprint.

- **Policy Alignment** – Capacity-focused DSM would support BC Hydro in meeting its self-sufficiency requirement (*CEA*, section 6.2) and the 93 per cent clean objective as part of the *CEA* (*CEA* objective 2(b)).

**Execution**

BC Hydro will design and then launch an industrial load curtailment offer and capacity-focused programs.

**Risk Mitigation**

BC Hydro will employ the same risk mitigation tactics as for energy-focused DSM. Refer to section 9.4.1.1.

**9.4.1.4 Future Approval Process**

Pursuant to subsection 44.2(1)a of the *UCA*, BC Hydro will file an application with the BCUC for approval of expenditures related to the DSM Plan. It is expected that the application will include an updated DSM Plan that will reflect new information
available at the time of filing on plan performance, DSM costs and energy savings opportunities.

9.4.2 Build and Reinvest More

9.4.2.1 Action 4. Continue to Pursue Site C

Recommended Action: 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, subject to environmental certification and fulfilling of the Crown’s duty to consult, and where appropriate, accommodate Aboriginal groups.

Site C includes the development of a 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 and Peace Canyon and the respective Williston and Dinosaur reservoirs.

Site C is currently in the early stages of a harmonized federal-provincial environmental review, which includes a joint review panel process.

Justification

Site C is needed at its earliest in-service date to provide BC Hydro with clean energy options to meet the mid Load Forecast and shortly after F2022 for the mid Load Forecast without Initial LNG load. Detailed discussion of the timing for the need of Site C to meet load requirements is provided in section 6.4.2 and 9.2.

- Cost-Effectiveness – Site C continues to be a cost-effective resource compared to other clean or renewable resource options in the majority of cases. With the energy and/or capacity requirements, portfolio analysis consistently concluded with the selection of Site C in the optimal portfolio regardless of market scenarios. Refer to section 6.4.
Site C also provides ancillary benefits to the electric system, including shaping and firming capability and wind integration capability. Further discussion of Site C analysis is provided in section 6.4.3.

While gas-fired generation can also be a cost-effective source of peaking capacity, as discussed in section 6.2, the 93 per cent clean energy objective and GHG reduction objective make gas an unattractive or unattainable option to replace the amount of capacity provided by Site C.

- **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 GDP and employment. Detailed discussions of environmental and economic development attributes are included in section 6.4.4 and 6.4.5 respectively.

**Project Execution**

- **Multi-Stage Development Process** – Consistent with best practices for large infrastructure projects, BC Hydro adopted a multi-stage approach for the evaluation of Site C. This process provides the Province with multiple milestones for assessing Site C and deciding whether to proceed to the next stage.

  - **Stage 1: Review of Project Feasibility** – During Stage 1, existing studies and historical information related to engineering, costs, environment, consultation and Aboriginal groups were reviewed. At the end of Stage 1, BC Hydro determined that Site C was feasible and recommended to the B.C. government to move Site C forward to the next stage of planning and development.
Stage 2: Consultation and Technical Review – Stage 2 of the Site C project included consultation with the public, Aboriginal groups, communities and property owners, as well as initial discussions with Alberta and the Northwest Territories. Stage 2 also included baseline environmental and socio-economic studies, as well as engineering and technical studies regarding the design, construction and operation of the proposed project.

Stage 3: Environmental and Regulatory Review – Site C is now in the environmental and regulatory review phase, which includes a cooperative federal-provincial environmental assessment, including a joint review panel. It includes multiple opportunities for participation by the public, Aboriginal groups, all levels of government, and other interested groups.

Stage 4: Detailed Design and Procurement – Subject to environmental certification, Stage 4 would include the conclusion of procurement, design and construction planning. Stage 4 would also provide a decision point for the Province to review Site C and decide whether to proceed to Stage 5.

Stage 5: Construction – The final stage of the Site C project is construction, estimated to take approximately seven years for the first unit to be in service.

Current Status – Stage 3 – Site C is currently in the early stages of a cooperative federal-provincial environmental assessment. As part of an environmental assessment of Site C, BC Hydro is identifying and assessing potential project effects, including environmental, economic, social, heritage and health. Where effects cannot be avoided, BC Hydro is identifying and evaluating options for mitigation.

The Site C project requires environmental certification and other regulatory approvals — including provincial permits and federal authorizations — before it can proceed to construction. In addition, the Crown has a duty to consult and,
where appropriate, accommodate Aboriginal groups.
The environmental assessment process for Site C is anticipated to take approximately three years to complete. A high-level schematic of the regulatory timeline is as follows.

### ENVIRONMENTAL ASSESSMENT TIMELINE

<table>
<thead>
<tr>
<th></th>
<th></th>
<th></th>
</tr>
</thead>
<tbody>
<tr>
<td>24 months</td>
<td>8 months</td>
<td>6 months</td>
</tr>
<tr>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>• Canada-BC Agreement on EA process</td>
<td>• Panel’s sufficiency review of EIS</td>
<td>• Draft Referral Package Preparation (EAO)</td>
</tr>
<tr>
<td>• Advisory Working Group</td>
<td>• Submissions (including from Aboriginal groups)</td>
<td>• Steering Committee Review (EAO, CEA Agency, Responsible Authorities)</td>
</tr>
<tr>
<td>• Environmental Impact Statement (EIS) Guidelines</td>
<td>• Public hearings</td>
<td>• Decision by Ministers/Cabinet</td>
</tr>
<tr>
<td>• EIS (Application)</td>
<td>• Panel report</td>
<td></td>
</tr>
<tr>
<td>• Working Group Review of EIS Guidelines and EIS</td>
<td></td>
<td></td>
</tr>
<tr>
<td>• Public comment periods</td>
<td></td>
<td></td>
</tr>
</tbody>
</table>

### ABORIGINAL CONSULTATION AND ACCOMMODATION DISCUSSIONS

**Risk Mitigation**

Consistent with good practice for a large infrastructure project, BC Hydro has reviewed the key project risks and has mitigation strategies in place for each risk identified. An overview of some key project risks and mitigation strategies is as follows.

- **Regulatory process** – The regulatory process for Site C is determined by the federal and provincial regulatory bodies, and is subject to changes in schedule and/or scope. During Stage 2, BC Hydro undertook project definition work, early environmental studies, and consultation with First Nations and the public in order to determine whether it was prudent to proceed to the Environmental Assessment. This preparatory work mitigates the risks of a process delay.
In February 2012, the federal and provincial governments announced that an agreement had been finalized for a harmonized environmental review of the Site C project, including a joint review panel. This agreement identified target timelines associated with the key steps of the co-operative review process.

- **Achieving Accommodation Agreements with First Nations, where Appropriate** – The Crown has a duty to consult, and where appropriate, accommodate Aboriginal groups. BC Hydro has currently engaged 51 Aboriginal groups in B.C., Alberta, and the Northwest Territories on the topic of Site C. BC Hydro has negotiated consultation agreements with groups where more in-depth consultation on Site C is required. BC Hydro currently has 12 consultation agreements which cover 15 First Nations in B.C., Alberta, and the Northwest Territories.

- **Geotechnical Conditions** – Unexpected geotechnical ground conditions during construction have the potential to cause cost increases or schedule delays. In order to mitigate this risk, the Site C team undertook a design optimization process before proceeding to Stage 3 to upgrade the historical design to meet current seismic, safety, and environmental guidelines. 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, comprised of global experts in hydroelectric development, reviewed and provided feedback on BC Hydro’s design choices for Site C.

- **Project Costs** – The final cost estimate for a capital project can only be known after a competitive procurement process is complete and a final bid is accepted. Due to engineering, environmental, and consultation work done in Stages 2 and 3, the Site C project 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 (Site C has a Class 3 cost estimate, as compared to
the majority of the other resource options in the IRP that are based on Class 4
or 5 estimates). The Site C cost estimate includes an appropriate level of
contingency to reflect uncertainty in future conditions.
BC Hydro’s capital cost estimate for Site C has undergone an external peer
review by KPMG. This peer review is good due diligence as it gives BC Hydro
confidence that the methodologies and assumptions used in the cost estimate
are appropriate.

Rate Impact & Future Approval Process
There is no effect on today’s BC Hydro rates from Site C, as costs are deferred until
the project begins generating electricity. This ensures that the costs for Site C are
paid by the ratepayers who are benefiting from the project. All costs for Site C will be
reviewed by the BCUC for prudency prior to being recovered from rates.

BC Hydro is committed to keeping rates as low as possible. To reduce the rate
impact on customers, 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.

9.4.2.2 Action 5. Develop Revelstoke Unit 6

Recommended Action: Begin work to allow the sixth generating unit at
Revelstoke Generating Station to be built by F2019, adding 500 MW of peak
capacity to the BC Hydro system.
BC Hydro will undertake the definition and implementation work\(^9\) to allow Revelstoke Unit 6 to be built by F2019, adding approximately 470 MW of dependable capacity to the BC Hydro system.

The direct capital cost of the project, in May 2012 constant dollars, is $340 million ($420 million loaded)\(^{10}\). BC Hydro will spend up to $150 million over the next three years to ensure Revelstoke Unit 6 is available for its earliest in-service date.

The role of Revelstoke Unit 6 in meeting BC Hydro’s need for capacity is discussed in sections 6.10.3 and 6.10.5.

**Justification**

The need for capacity resources has increased significantly with strong load growth in the mining and oil and gas sectors that will require both Revelstoke Unit 6 and Site C. Revelstoke Unit 6 is the last of the four additional units at the Mica and Revelstoke dams and is the most cost-effective capacity resource that can be delivered with certainty and meets the CEA requirements for self-sufficiency and 93 per cent clean energy objective.

- **Cost-Effectiveness** – Revelstoke Unit 6 is the most cost-effective dependable capacity option currently available to BC Hydro. The cost comparison of all available capacity resources is set out in Table 6-29, and discussed in section 6.10.3 and the conclusions are discussed in section 6.10.7.

- **Economic and Environmental Attributes** – Revelstoke Unit 6 installation work will be contained within the existing footprint of the Revelstoke Generating Station, and therefore, will have minimal additional environmental impact.

---

\(^9\) Project schedule has not been finalized, the duration of Definition phase work will be defined as the more detailed project planning is underway. Based on current preliminary assessment, Project Implementation phase is expected to be around three years.

\(^{10}\) The project capital cost is an update to the Revelstoke Unit 6 project capital cost shown in the 2010 Resource Options Report attached to the IRP as Appendix 3A-1.
Based on the 2010 Resource Options Report, preliminary assessment of the economic development attributes shows that Revelstoke Unit 6 is to contribute about $188 million to Provincial GDP, $27 million to provincial government revenues, and to create about 2,390 jobs during construction and operation.

- **Flexibility** – Revelstoke Unit 6 would provide long-term (50+ years) dependable capacity to BC Hydro’s ability to reliably meet the winter peak demand while also providing significant operational and ancillary services including system shaping, operating reserves, load following and rotational energy, that are required to support intermittent resources.

- **Alignment with CEA** – Revelstoke Unit 6 does not emit GHGs, and supports the CEA 93 per cent clean energy objective (CEA Objective 2(c)).

**Execution**

Revelstoke Unit 6 is currently in Feasibility stage with a low development uncertainty and medium cost uncertainty of +50 per cent/-15 per cent. With the recent construction of Revelstoke Unit 5 and current construction of Mica Units 5 and 6, BC Hydro has a good sense of the project costs and has a construction team working the area. An overview of the key steps to project definition and implementation phases is as follows.

The Definition Phase is to develop and refine project details to the extent that the Implementation Phase scope, risks, and costs are well defined. BC Hydro aims to achieve project cost accuracy on the order of +15 per cent/-10 per cent at the Implementation Phase approval stage. Deliverables in Definition phase include:

- Initiation of the process to obtain environmental approvals;
- Consultation with public stakeholders and affected First Nations;
- Updated assessments of the benefits associated with the project;
Chapter 9 - Recommended Actions

- Approved User Requirements documents;
- Approved procurement strategy;
- Preliminary design of the project;
- Preliminary design of the associated transmission requirements;
- Business case for implementation of the project.

The Implementation Phase begins with the approval of the Implementation Phase Business Case, and an Expenditure Authorization Request.

Risk Mitigation

- Business Risk Management – This Definition phase work will maintain the earliest in service date of F2019 for Revelstoke Unit 6. Business risks include the environmental review process for Revelstoke Unit 6, stakeholder engagement and First Nations consultation to consider the cumulative impacts and issues associated with Revelstoke Unit 6.

- Definition Phase Risk Management
  - Scope Risks: Scope risk is limited since Revelstoke Unit 6 is fairly well defined and is to be located in the existing Revelstoke Generating Station.
  - Schedule Risks: Revelstoke Unit 6 is needed at its earliest in-service date, which calls for an investment decision to support the project implementation with well managed project schedule to minimize schedule delays.
  - Cost Risks: The major cost risks for the Definition phase are related to First Nation consultation and accommodation activities.
  - Resource Risks: Given the significant number of large capital projects undertaken by BC Hydro, BC Hydro will need to ensure project resources are optimized and adequate resourcing is available.
Future Approval Process

Pursuant to subsection 7(1)(c) of CEA, BC Hydro is exempted from sections 45 to 47 of the UCA (CPCN). The project may be subject to federal or provincial environmental assessments.

9.4.2.3 Action 6. Bridging Capacity from Existing Resources

**Recommended Action:** Fill the short-term peak capacity gap from F2016 to F2021 with a combination of market purchases first, power from the Columbia River Treaty second, and extending the existing back-up use of Burrard Thermal Generating Station, if required and as authorized by regulation.

The market, backed up by the Canadian Entitlement provided under the Columbia River Treaty, will be the first resource relied upon to meet any system capacity shortages. If those prove to be inadequate, BC Hydro will rely upon Burrard.

BC Hydro does not foresee any changes in how Burrard is operated currently which is an average of 12 days per year. This would extend the timeline of relying upon Burrard for dependable capacity (until Mica Units 5 and 6, the Interior-to-Lower Mainland transmission line (ILM or 5L83) and the third Meridian transformer are in service) to be available until Revelstoke Unit 6 is in-service and, if required, until Site C is in-service.

The costs to maintain the market and Canadian Entitlement capacity options are expected to be incidental business expenses without a need to make explicit options/reservation contracts over and above normal business practices. Burrard maintenance and operational costs are expected to be an extension of current activities. The F12 and F13 plans for Burrard OMA are $13.4 and $13.7 million respectively, and F12 and F13 plans for Burrard capital are $6.3 and $11.5 million respectively.
Justification

As discussed in section 6.10.3 and concluded in section 6.10.5, relying upon the markets, the Canadian Entitlement and Burrard as bridging resources is beneficial as follows:

- These are existing resources that are readily available today;
- The costs for these bridging capacity resources are lower than the alternative solution of building new gas-fired generation;
- The sunk costs of the bridging resources is much smaller than new gas-fired generation which will allow most of the costs to be avoided if the need for capacity is not as great as expected due to lower load growth or LNG loads do not commit as quickly as indicated;
- Gas-fired generation can be difficult to site and approve and constructing by F2017 may be a challenge; and
- If further contingencies occur, both resources will be required. More detailed discussion is included in section 9.4.4.3.

Execution

To ensure BC Hydro has adequate capacity resources available to bridge to Revelstoke Unit 6 and Site C, BC Hydro and Powerex will undertake three activities:

- Continue to monitor market conditions and U.S./Alberta transmission system development to facilitate and ensure that BC Hydro has access to 500 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 Canadian Entitlement, trade commitments and market optimization to allow 500 MW of the Canadian Entitlement to be available to back up the 500 MW of market purchases; and
- Enhance the maintenance and operations plans for Burrard to ensure Burrard is available for at least 450 MW for a period that extends the current reliance from F2016\(^{11}\) until F2022 when both Revelstoke Unit 6 and Site C are expected to be in-service. Thereafter, Burrard will continue to be relied upon for emergency service.

**Future Approval Process**

Relying upon the market and Canadian Entitlement for short-term capacity needs from F2016 to F2021 does not meet the self-sufficiency requirements in section 6 of the *CEA*. A regulation pursuant to section 6(3) of *CEA* could authorize this short term reliance.

Burrard Thermal Generating Station's firm energy contribution is zero GWh/year as a result of subsections 3(5), 6(2)(d) and 13 of *CEA*. Pursuant to section 2 of the Authorization for Burrard Thermal Electricity Regulation\(^{12}\), BC Hydro is authorized to rely on and operate Burrard's dependable capacity of 900 MW until Mica Units 5 and 6, ILM or 5L83 and the third transformer at Meridian Substation in the City of Coquitlam are providing service. Reliance upon Burrard as required for this Recommended Action would require an amendment to the Authorization for Burrard Thermal Electricity Regulation to allow BC Hydro to continue the currently authorized use of Burrard for capacity until Revelstoke Unit 6, and if necessary Site C, are providing service.

\(^{11}\) Reliance upon Burrard for capacity purposes has been provided in the "Burrard Thermal Electricity Regulation" until Mica 5/6, ILM and Meridian Transformer are expected to be in service which is estimated to occur by F2016.

9.4.2.4  Action 7. Investigate and Advance Additional Resource Smart Projects

Recommended Action: Continue to investigate and advance cost-effective Resource Smart projects to utilize the remaining, untapped capacity within BC Hydro’s existing hydroelectric system.

BC Hydro is investing in several large scale generation redevelopment and growth projects and smaller scale refurbishment and replacement projects associated with its Heritage hydro resources. These projects renew these facilities and provide incremental capacity and energy benefits when economically feasible. There may be options to advance the development of the additional capacity benefits that should be considered as refurbishments/replacements are undertaken.

Examples of Resource Smart projects include:

- GM Shrum – potential capacity upgrades of 105 MW provided through equipment upgrades and revising the Water License;
- Kootenay Canal – potential of an additional 7 to 9 MW per unit from generator and turbine upgrades;\(^{13}\)
- Mica – potential estimated additional capacity resources are 20 MW per unit for G1/G2 and approximately 40 MW for G3/G4 if the unit transformers were uprated (either replaced or adding additional cooling). Surging on G3 and G4 would also need to be addressed to achieve these potential resources;
- Bridge River – rewind/replace stators on G4 (10 MW) and G5 (20 MW) to restore original design capacity;
- Falls River Generating Station – addition of 13 MW capacity;

\(^{13}\) Based on a preliminary analysis, the Kootenay Canal unit capacity has the potential to be increased from 147 to 156 MVA for the generator, and 145.4 to 152 MW for the turbine. However, even if the unit capacity was increased, the units were significantly de-rated due to high ambient cooling water temperature; also worth-noting is the additional capacity is only available when the head is high enough.
**Recommended Actions**

- Cheakamus – rewind/replace stator to increase capacity from 70 MW to 90 MW for two units (low value due to timing of generation); and
- Seton Generating Station – potential of an additional 4 MW if degrading stator insulation is addressed.

**Justification**

As discussed in section 6.10.3 and concluded in section 6.10.5, BC Hydro has both a short-term capacity gap that will require market/Canadian Entitlement/Burrard bridging resources and a longer term capacity need. Resource Smart projects are attractive as follows:

- Making changes and upgrades in existing facilities can be more cost-effective than building new facilities or purchasing from IPPs or third parties in B.C.;
- They have minimal environmental impact as they are upgrades on existing BC Hydro generation facilities; and
- They can have shorter project assessment and construction lead time than other alternatives, but can be subject to regulatory and water license approvals.

**Execution**

Given the current planned work at Ruskin Upgrade Project, Mica Generating Station (Mica Units 5 and 6) and John Hart Generating Station Replacement Project, limited preliminary cost estimates of additional cost-effective Resource Smart capacity options will be developed in the BC Hydro 20-year Generation Capital Plan. This plan will identify some of the available projects that have the potential to provide additional capacity, but development of these resources will be pursued in the future. Further feasibility analysis of uprating projects will only be considered when existing equipment is at end of life, scheduled for replacement, and in the context of the current economics.
Risk Mitigation

The very heavy workload currently underway with the Generation refurbishment plan will limit the advancement opportunities associated with most of these projects. The investigation of advancing these projects will only be undertaken while ensuring existing refurbishment projects remain on track and properly supported.

Future Approval Process

Advancing Resource Smart capacity projects may require a CPCN or section 44.2 UCA expenditure approval if the capital expenditure is above $100 million, and may trigger environmental assessments.

9.4.2.5 Action 8. North Coast Transmission Upgrade

Recommended Action: Reinforce the existing 500 kV line from Prince George (Williston Substation) to Terrace (Skeena Substation) to meet new demand on the North Coast.

The three 500 kV line segments, 5L61, 5L62, and 5L63, that run from Williston to Skeena would be upgraded with the addition of series compensation and shunt capacitors for reactive voltage support. No new transmission rights-of-way are required, however, new sites for the series capacitor stations may be necessary.

The project is in the early stages of planning, design, and approvals and needs to be in service by F2016 in order to meet requirements of the Initial LNG facilities.
Table 9-13  Transmission Reinforcement Earliest Required In-Service Date and Direct Costs

<table>
<thead>
<tr>
<th>Reinforcement</th>
<th>Earliest Required In-Service Date</th>
<th>Direct Cost ($2011 million)</th>
<th>Funding Required to Maintain Earliest In-Service Date ($ million)</th>
</tr>
</thead>
<tbody>
<tr>
<td>New Williston – Skeena 500 kV series capacitor stations/shunt compensation</td>
<td>F2017 (2016)</td>
<td>95(^{14})</td>
<td>0</td>
</tr>
</tbody>
</table>

**Justification**

BC Hydro investigated the electrification of LNG and mining loads in the North Coast region and along the Northwest Transmission Line (NTL) corridor. It focused on the bulk transmission reinforcements which allow serving the incremental North Coast loads using clean energy flowing from Central Interior. As shown in section 6.5, BC Hydro has built up a surplus of clean energy by F2016 and initially will be able to supply the load in this region without additional energy acquisitions. As shown in sections 6.10.3 and 6.10.5, BC Hydro is recommending a bridging strategy to allow the system to meet these and other system load capacity needs until Revelstoke Unit 6 and Site C are in-service.

The approximately 800 MW post-NTL load serving capability of the North Coast region is not sufficient for serving the Initial LNG and other mining loads in the region. Series compensation of the three North Coast 500 kV lines 5L61, 5L62, and 5L63 plus addition of shunt reactive power along this path can provide approximately 580 MW incremental load serving capability for a total of 1,380 MW in the North Coast region.

\(^{14}\) Preliminary estimates, based on experience with previous capacitor station projects. BC Hydro is currently updating the costs for the transmission reinforcements required between Prince George and Kitimat.
Execution

The initial steps of this project are already underway. Initial scoping of the project is complete and internal approvals have been obtained. Consultation with First Nations and stakeholders is underway. BC Hydro is currently completing the detailed project design and equipment specifications. BC Hydro will ensure that the Initial LNG facilities are committed to the expected in-service dates prior to completing equipment orders and undertaking the construction of the upgrades.

In addition to series compensation, BC Hydro continues to analyse requirements to interconnect Initial LNG that may result in additional transmission upgrades or infrastructure.

Risk Mitigation

The final decision to pursue a transmission upgrade will be made as the new loads in the current forecast reach critical milestones. Should the anticipated LNG and mining loads not materialize in the timeframe expected, the upgrades could become stranded assets until other load requirements or generation potential utilized the capacity. BC Hydro will assess the timing and likelihood of additional LNG and mining loads on the North Coast to assess upgrade project timing. The stranding risk will be mitigated by capital contributions and security provided by LNG and mining loads.

The upgrades of existing transmission lines and series compensation facilities between GMS and Williston do not require any new rights-of-way and therefore most of the risks associated with these upgrades are typical procurement, project management, financial and construction risks.
**Future Approval Process**

If the project cost is greater than $100 million, and depending on the final scope and nature of the project, BC Hydro may be required to apply to the BCUC under either section 44.2 (expenditure approval) or section 46 (CPCN) of the UCA. The project may also be subject to a federal (Canadian Environmental Assessment Act (CEAA)) assessment, depending on the final characteristics of the project and proposed changes to federal environmental laws, including CEAA.

**9.4.3 Buy More**

**9.4.3.1 Action 9. Develop 2,000 GWh/year Clean Procurement Option**

**Recommended Action: Design an energy procurement process to acquire about 2,000 GWh/year from clean energy producers for projects that would come into service in the F2017 to F2019 timeframe.**

The design work on the energy procurement process will identify ways and means of delivering energy in the F2017 to F2019 timeframe that results in cost-effective supply of clean energy. Work will be done with resource developers to gain agreement on procurement design and Electricity Purchase Agreement (EPA) parameters.

Design work is expected to be completed by mid-year of F2014.

Expected cost for the design work over F2013 and F2014 is approximately $3 million.\(^\text{15}\)

\(^{15}\) The short-term cost estimate pertains to acquisition process design and full implementation.
Justification

Clean energy independent power producers (IPP) resources are the marginal resource for BC Hydro’s supply of energy. The use of gas is limited and reserved for capacity resources as discussed in section 6.2. The IRP analysis demonstrates that:

- With the mid Load Forecast including Initial LNG, BC Hydro will have a remaining short-term energy gap of up to 3,500 GWh/year after committing to DSM Option 3 and Site C. An acquisition of about 2,000 GWh/year would result in a further 1,500 GWh/year reliance on non-firm/market.

- Preliminary analysis shows that the rate impact of 2,000 GWh/year acquisitions for the interim period is 2.5 per cent lower than acquiring the full 3,500 GWh/year to address the shortfall.

- An additional 1,500 GWh/year of non-firm/market energy would result in a total non-firm/market energy reliance of 5,600 GWh/year. This is within the 4,500 to 6,500 GWh/year reliance that BC Hydro believes can be reasonably undertaken with the current markets.

This approach allows the system to become deficit for a period prior to the addition of Site C’s 5,100 GWh/year of energy contribution and reduces the time that BC Hydro is expected to be in surplus afterward. Although this approach does not strictly meet the requirements of the self-sufficiency policy requirement, it is a balanced approach between cost savings and reliability. Detailed discussion of the IPP analysis is provided in section 6.8.2.

Execution

Depending on the level of load growth realised in B.C. and consistent with the recommendations provided in the Merrimack Report, submitted to BC Hydro in February 2011, the necessary acquisitions could be completed through a variety of cost-competitive processes such as Requests for Proposals, Standardised Offers or
bilateral discussions. BC Hydro will also assess the options for the potential energy acquisition from clean energy producers for projects that would come into service in the F2017 to F2019 period. These options include the Standing Offer Program, Integrated Customer Solutions, Net Metering, Distributed Generation, IPP contract renewals and new clean power procurements. The final mix of approaches selected by BC Hydro will be dependent on the volume and timing of energy required, potential sources of energy available and a determination of the most effective method to acquire the required resources.

Amongst these acquisition opportunities that will be assessed, the advent of smart meters and a modernized grid may facilitate the development of more Distributed Generation.\(^{16}\) The recently amended Net Metering Tariff coupled with a new improved website and focused promotion of the amended tariff should result in more net metering projects being developed. Furthermore, in response to stakeholder interest, BC Hydro is committed to defining and articulating a distributed generation approach. As part of that commitment, BC Hydro is examining the practices of other jurisdictions; analyzing our existing acquisition programs and offers to ensure appropriate alignment between the various project thresholds; and identifying possible barriers, and their removal, to support development of new small scale distributed generation projects. The results of this work may lead to the design of an offer for distributed generation projects targeting smaller scale projects greater than 51 kW and up to a threshold to be determined. This will enable more distributed generation in B.C., building towards a seamless suite of acquisition offers that covers our customers’ needs.

As a result of the IRP analysis and the Merrimack Report, specific elements of future procurement processes will include:

\(^{16}\) DG can be characterized as small scale projects that are developed by customers or IPPs, on or at customer sites, or close to the load they are intending to serve and that require interconnection on the distribution system. For additional details, please refer to section 3.6.1.
1. Consultation with First Nations in respect to proposed procurement design and ensuring adequate consultation is undertaken for potential projects to be awarded an EPAs;

2. Significant transparency and stakeholder input as part of the procurement design;

3. Greater emphasis on project viability criteria and transparent weightings for price and non-price factors to evaluate bids to select procurements. Section 6.8.5 lists the key IRP conclusions on price and non-price factors including the need to address surplus energy during freshet conditions;

4. Commercial terms that allocate risk to the party best able to manage the risk and deliver the most cost-effective projects;

5. A two-stage procurement process that includes selecting a short list of bidders and then providing short listed bidders the opportunity for a series of competitive negotiations and then final submissions to BC Hydro;

6. Simultaneous competitive negotiations that allow consideration of value added provisions under standards that assure fairness;

7. Development of final portfolios from procurements is based on bid price, interconnection and transmission upgrades; and

8. Modifying the evaluation methodology to reflect a second load centre on the North Coast in addition to the Lower Mainland.

**Target Volume:** 2,000 GWh/year

**Commercial Operation Date:** F2017 – F2019

**Risk Mitigation**

Deferring the need for acquisition until F2017 is largely driven by the change in planning criteria from critical to average water. While BC Hydro will work with IPPs
on procurement design work in F2013, which will have minimal relative cost, final
decisions on the timing and initiation of the procurement process as well as the
volume of energy are unlikely to be made earlier than F2014 (mid 2013) after other
acquisition options have been considered and the new loads in the current forecast
reach critical milestones. This will minimize the risk that BC Hydro acquires either
too much or too little clean energy.

BC Hydro anticipates that some of the risks of not acquiring the amount of energy
targeted in the required timeframe include:

- Receiving an insufficient number of proposals or proposals that do not meet the
  required amount of energy;
- Failure to enter into EPAs with proponents due to proponents withdrawing their
  proposals, or because the final provisions of the EPA could not be agreed
  upon;
- Project development delays or cancellation and
- Transmission delays.

BC Hydro engages IPPs as it designs any new procurement processes to minimize
these risks while still meeting BC Hydro’s targets. BC Hydro will reserve the
discretion to award EPAs and/or terminate the process.

Future Approval Process

Short term reliance upon non-firm energy backed up by market purchases beyond
the average water reliance upon the Heritage Hydro system does not meet the strict
requirements of self-sufficiency under section 6(2) of the CEA. A regulation pursuant
to section 6(3) of CEA could authorize this short term reliance.

EPAs must be filed with the BCUC for acceptance under section 71 of the UCA. In
addition, individual IPP projects may be required to undergo provincial (British
Columbia Environmental Assessment Act (BCEAA)) environmental assessments, depending on the size and characteristics of the individual projects.

9.4.3.2 Action 10. Explore Pumped Storage

Recommended Action: Explore pumped storage capacity options that focus on reducing the lead time to in-service dates and where and how to site future pumped storage in the province, should they be needed

Pumped storage is a technology that uses energy during off-peak/low cost periods to pump water into an upper containment and subsequently releases the water to generate electricity during on-peak/high cost periods. Pumped storage is a clean capacity resource when combined with clean energy consumption during the pumping phase. Pumped storage has only been developed once in Canada in the 1950’s, and has never been built in B.C., but is a proven technology at sites around the world. More discussion on pumped storage is provided in section 6.10.3.4.

BC Hydro has conducted basic studies of pumped storage options as part of the 2010 Resource Options Report (Appendix 3A-1), both for Lower Mainland/Vancouver Island greenfield sites and as an upgrade to the Mica facility.

The Recommended Action is to work with IPP resource developers to assess future pumped storage options and to assess how these could be advanced to ensure they can be built and completed within a defined and fixed timeframe so that they can be relied upon as a future capacity resource option.

The Lower Mainland and Vancouver Island Pumped Storage Report in 2010 Resource Options Report (Appendix 3A-30) showed an expected capital cost ranging from $1.3 to $3.3 billion dollars for a Lower Mainland/Vancouver Island pumped storage facility. It is expected that full development costs (including feasibility studies, final design and required consultation and approvals) could approach approximately 5 per cent of total project costs. The short-term (F2013 and
F2014) cost to design and implement a procurement process is anticipated to be about $2.5 million. Although the requirements will not be fully known until the process is complete, BC Hydro anticipates that funding early stage development work will require at least an additional $7.5 million, for a total current funding requirement of $10 million.

Justification

As discussed in section 6.10, BC Hydro has both long-term and contingency capacity needs. There are very significant new loads contemplated in the IRP including mining and LNG and there is significant uncertainty in the capacity contributions from DSM and intermittent resources. BC Hydro plans to complete the last of its clean capacity resources in the IRP (Revelstoke Unit 6 and Site C) and thereafter must seek additional sources of capacity. The two key options that have a significant potential include pumped storage and gas-fired generation.

While gas-fired generation is a low cost resource (under current gas/GHG prices) that is available for the short-term gap period; its use is limited due to the 93 per cent clean generation objective. BC Hydro is planning to maintain and preserve the optionality around gas generation for situations when no other options are available, when there may be an ability to avoid significant transmission costs and under contingency conditions.

The development of pumped storage is a viable resource that warrants further consideration, particularly as it is a capacity resource that is able to be consistent with the current clean generation objective. Siting pumped storage in the Lower Mainland/Vancouver Island region has the additional benefit of deferring further ILM transmission lines. Further work is required for pumped storage to be a credible and timely option to meet future or contingency capacity requirements of the system.
**Execution**

A significant number of pumped storage sites were identified in the Lower Mainland/Vancouver Island region in the 2010 Resource Options Report. There is a long lead time of between eight to ten years to fully design, permit and build a large pumped storage facility. BC Hydro needs to advance the development of pumped storage facilities to be ready to meet future capacity requirements.

BC Hydro will develop and implement a process to enter into 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 up to 1,000 MW of pumped storage projects, with a commercial operation date of not earlier than the early 2020s. Given the work will be occurring in advance of any commercial commitments from BC Hydro for construction and operation of a pumped storage project, BC Hydro will be open to sharing some of the cost of some of the work.

BC Hydro’s goal is to have the selection process complete and developers undertaking feasibility work by F2015.

Depending on the results of the feasibility work by developers and the future requirement for capacity, this may lead to a future decision to undertake more complex and costly development work, such as final design, engineering and permitting. Conversely, if the situation changes regarding the need for future capacity, or there are other more cost-effective options aligned with government policy, BC Hydro may terminate the process at that point. All assessments and actions will be guided by a determination of the most cost-effective approach to advance a potential capacity resource.
Risk Mitigation

There are three key risks in this approach to pumped storage development for BC Hydro:

1. Given the time, energy and resources required, there may not be sufficient developer interest to facilitate the investigation of good potential sites;

2. BC Hydro may be making expenditures in advance of the need for new capacity being confirmed; and

3. In the absence of pumped storage facilities, a new ILM line will be required between F2024 and F2030.17

To mitigate these risks BC Hydro will:

- Advance the pumped storage development through the early, low cost development phases and will avoid major expenditures until a need is confirmed;

- Engage potential pumped storage developers and other stakeholders as it advances this action item. These discussions will focus on opportunities to identify and investigate potential sites at minimal cost with BC Hydro making no commitment to develop a site until it is proven to be cost-effective and required;

- Explore potential risk and cost sharing between BC Hydro and the developer(s) through pre-established and mutually agreed upon development stages.

The level of cost sharing required by potential developers will be a key criteria used to select developers and projects. BC Hydro will reserve the discretion to terminate the investigation activity and process. Committing in advance to project development regardless of viability, price or other terms is not in the interest of ratepayers. To

---

17 In modelling, pumped storage is replaced with Kelly Lake SCGTs, therefore did not advance Williston to Kelly Lake transmission line.
mitigate the risk that the proposed process does not identify a cost-effective, feasible
option, BC Hydro will continue to advance the Mica pumped storage option.

Once a developer has been selected through a procurement process, a further risk
to BC Hydro is that the developer may terminate the agreement and work on a site
that BC Hydro feels may have potential, or the developer may be unsuitable for the
more complex and risky work of late stage development, construction or operation.
To mitigate this risk, the agreements with developers will carefully define termination
rights and will contain some form of “step in” rights for BC Hydro in the event that the
developer is unwilling or unable to continue development of a promising site.

Future Approval Process

The exploration of pumped storage as an option does not require any approvals. If
any pumped storage projects proceed beyond the exploration stage, the contracts
resulting from this Recommended Action may be “energy supply contracts” as
defined in section 68 of the UCA depending on the nature of the contract and would
be filed with the BCUC for acceptance under section 71 of the UCA. In addition,
individual projects may be required to undergo federal (CEAA) or provincial
(BCEAA) environmental assessments, depending on the size and characteristics of
the individual projects and proposed changes to federal environmental laws,
including CEAA.

9.4.4 Prepare for Potentially Greater Demand

9.4.4.1 Action 11. New Transmission Infrastructure from Peace River to
North Coast

Recommended Action: Undertake work to maintain the earliest in-service date
for a new 500 kV transmission line from Prince George to Terrace and Kitimat,
and from the Peace River region to Prince George.
There are three key new 500 kV transmission lines that may be needed to supply the LNG3 load scenario under the assumption that this load would be supplied from the system or as back-up local clean resources and gas-fired generation:

- A new 500 kV transmission line from Williston substation near Prince George to the Skeena Substation near Terrace will be needed to both deliver energy and capacity;
- Two new 500 kV transmission lines from the Skeena Substation near Terrace to a new 500 kV substation near Kitimat will be needed to both deliver energy and capacity; and
- A new 500 kV transmission line from Peace Region to Williston near Prince George may be needed to deliver energy from clean resources depending upon the resource portfolio.

BC Hydro recommends proceeding with the planning, preliminary design and consultation activities to prepare for the option of these new transmission lines to keep the system supply option open for LNG3. LNG3 may require supply as early as F2020. In the absence of additional LNG loads on the North Coast, these new lines will not be needed for North Coast supply.
Table 9-14  Transmission Reinforcement Earliest Required In-Service Date and Direct Costs

<table>
<thead>
<tr>
<th>Reinforcement</th>
<th>Earliest Required In-Service Date</th>
<th>Direct Cost ($2011 million)</th>
<th>Funding Required to Maintain Earliest In-Service Date ($ million)</th>
</tr>
</thead>
<tbody>
<tr>
<td>New 500 kV Williston – Skeena Transmission Line</td>
<td>F2020</td>
<td>1100</td>
<td>54(^{18})</td>
</tr>
<tr>
<td>New 500 kV Skeena – Kitimat Transmission Line</td>
<td>F2017</td>
<td></td>
<td></td>
</tr>
<tr>
<td>New 500 kV GMS - Williston Transmission Line</td>
<td>F2020</td>
<td>400</td>
<td>25</td>
</tr>
</tbody>
</table>

Justification

Section 6.5 analyzed the supply options for LNG3 with and without additional mining load growth in the North Coast region over and above the loads included in the mid Load Forecast with Initial LNG. Two supply options were considered:

- System wide clean resource supply including pumped storage capacity in the Lower Mainland region supplied to LNG3 in Kitimat through the additional transmission lines; and
- Local clean resources backed up by local gas-fired generation, this option would not require the additional transmission lines.

In the analysis, it was identified that there was an incremental cost of system supply with pumped storage and new transmission lines, however, the difference was not large and would be mitigated if gas-fired generation was built in the system. In addition, the ultimate supply for LNG3 would be based upon customer criteria for supply including stability and reliability considerations. It was determined that BC Hydro should continue to keep both options alive, hence, this Recommended Action is required.

\(^{18}\) Funding of the work to preserve the earliest in-service date is provided by project proponent.
An additional consideration for the GMS to Williston transmission line is ultimately the location of clean resources acquired, whether they are in the North Coast region or in the system more generally. If clean resources are to be acquired in the system generally, the optimized portfolio suggests that wind in the Peace River region is the most cost-effective. BC Hydro needs to continue to assess the likelihood of Peace River region wind as a leading cost-effective resource and the extent to which the transmission system must be built to deliver all wind output. It may be more cost-effective to reduce Peace River system output during high wind conditions or to curtailed wind at peak transmission flow periods versus building additional transmission lines.

**Execution**

Considering the long lead time for a new 500 kV circuit, it is justifiable to initiate the planning and approval phases of the project and secure the required rights-of-way. Project planning will be undertaken to determine the requirements to meet LNG3 load including the need for series compensation, reactive compensation and conductor sizing. With initial approvals, work will be undertaken to identify rights-of-way, consult and acquire rights-of-way.

**Risk Mitigation**

The key risks on this Recommended Action are timing for the supply option and initial cost coverage.

To ensure the project in-service date can be maintained, initial planning will be done and approvals obtained. Work will also be undertaken to ensure the project critical path will allow the currently required in-service date of F2019.

To minimize cost risk, the initial work will proceed now at minimal relative cost and final decisions on the timing will be made no earlier than F2014 after the new loads
in the current forecast reach critical milestones. This will minimize the risk that BC Hydro overbuilds the system or has stranded costs.

**Future Approval Process**

In view of the estimated cost of these transmission projects (more than $100 million), BC Hydro would apply for CPCNs under section 46 of the *UCA*. Based on the physical characteristics of the individual transmission projects as described in this IRP, the projects would likely require provincial environmental assessments (*BCEAA*). The transmission projects may also be subject to federal environmental assessment reviews under the *CEAA* depending on the final size and characteristics of the individual projects and the proposed changes to federal environmental laws, including *CEAA*.

### 9.4.4.2 Action 12. Develop Future Acquisitions for LNG3

**Recommended Action:** Develop procurement options for additional clean energy resources, backed-up by gas-fired generation—located either in the North Coast or both in the North Coast and across the province—for energy that could be delivered in the F2020-F2021 timeframe, should it be needed.

BC Hydro will initiate the design of procurement processes, at minimal relative cost, to ensure adequate volumes of clean energy projects can be advanced by developers to meet the potential load demands of additional LNG facilities. Depending on the commitments made by potential LNG loads in F2013 procurement processes may need to be activated in F2014.

The expected cost for the procurement option development over the next two years (F2013 and F2014) is approximately $2 million$^{19}$.

$^{19}$ Short-term cost estimate pertains to acquisition process design without implementation.
Justification

Section 6.5 analyzed the supply options for LNG3 with and without additional mining load growth in the North Coast region over and above the loads included in the mid Load Forecast with Initial LNG. Two supply options were considered:

- System-wide clean resource supply including pumped storage capacity in the Lower Mainland region supplied to LNG3 in Kitimat through the additional transmission lines; and
- Local clean resources backed up by local gas-fired generation (this option would not require the additional transmission lines).

In the analysis, it was identified that there was an incremental cost of system supply with pumped storage and new transmission lines, however, the difference was not large and would be mitigated if gas-fired generation was built in the system. In addition, the ultimate supply for LNG3 would be based upon customer preferences for supply including stability and reliability considerations.

Hence, BC Hydro needs to maintain both options to serve additional North Coast LNG facilities with clean electricity. The load scenario with a third LNG facility studied in the IRP would see additional load of about 12,800 GWh/year being required in the F2020 to F2026 timeframe. To meet these requirements beginning in F2020, the design of an acquisition process needs to be undertaken in F2013 and the process would need to be launched in F2014 to enable commencement of energy delivery in the F2020-F2021 timeframe. BC Hydro needs to develop a process with IPPs and LNG load proponents to develop a suite of clean projects that are available and can be built in time for customers’ needs.
Execution

BC Hydro will develop and potentially initiate procurement processes to enter into agreement with multiple developers to advance projects with initial supply reaching commercial operation date no later than Q3 of F2019. Given the uncertainty, timing and potential scope of the potential new LNG loads, the procurement processes will be competitive, flexible and targeted and designed to select preferred proponents and their projects. BC Hydro will focus on selecting potential developers with adequate scale and ability to make significant project investments despite uncertainty of final LNG decisions. Selection as a preferred proponent will then initiate further discussions to finalise commercial terms and development obligations.

As part of the design and execution of these potential procurements BC Hydro will explore, assess and develop approaches for First Nation consultations, commensurate with the scale of potential development activity.

Some of the key considerations for design of the procurements will be identifying

- Whether the procurements are centred on the North Coast or are system-wide,
- How to ensure that the processes will result in a competitive supply of clean electricity, and
- How to advance sufficient volume of projects in advance of final investment decisions by potential new loads and linking the development and operation of new clean energy supply with potential transmission investments and potential gas fired investments.

Target Volume: 10,000 GWh/year

Commercial Operation Date: Initial supply in Q3 of F2019
Risk Mitigation

BC Hydro anticipates that one of the more probable risks is not generating sufficient interests from potential developers to meet the volume and commercial operation dates required to serve the potential LNG loads. In addition, if BC Hydro takes a passive approach, BC Hydro may not be able to supply these loads. At the same time BC Hydro is at risk of making expenditures in advance of the need for new capacity being confirmed.

To mitigate these risks BC Hydro will engage potential developers and other stakeholders as it advances this action item. These discussions will focus on gaining optionality and capturing opportunities to identify and advance a sufficient volume of potential sites at minimal relative cost with BC Hydro making no final commitments to develop a site until final LNG investment decisions occur.

BC Hydro will also explore and pursue potential risk and cost sharing between BC Hydro, potential developers and potential LNG facilities through pre-established and mutually agreed upon development stages. BC Hydro will implement clear commercial terms to defer or discontinue further activities with proponents and projects if LNG loads are deferred or choose other supply solutions. Committing in advance to project development regardless of viability, price or other terms is not in the interest of ratepayers.

BC Hydro will also consult with First Nations and engage Government permitting authorities to develop procurement and development approaches designed to align with Consultation requirements and permitting expectations.

Section 6.8 provides more detailed discussions on the volume, timing and approach to future energy acquisitions; including the key parameters and considerations such as REC values, wind integration cost, wind integration limit, as well as the need for
ongoing management of energy acquisitions over freshet period to ensure prudent long-term energy position.

**Future Approval Process**

The design of a procurement process does not require any approvals. If the procurement process is initiated and EPAs are entered into, the EPAs must be filed with the BCUC for acceptance under section 71 of the *UCA*. In addition, individual IPP projects may be required to undergo federal (*CEAA*) or provincial (*BCEAA*) environmental assessments, depending on the size and characteristics of the individual projects and proposed changes to federal environmental laws, including *CEAA*.

**9.4.4.3 Action 13. Natural Gas-fired Generation to Provide Contingency Capacity Options**

*Recommended Action: Explore natural gas-fired generation options to reduce the lead time to in-service dates and to develop an understanding of where and how to site such future resources in the province, should they be needed.*

Gas-fired generation is the default incremental capacity resource when no other cost-effective capacity resources are available. The Recommended Action is to undertake work to develop natural gas-fired contingency options that focus on reducing the lead time to in-service dates and an understanding of where and how to site gas-fired generation in the province. Working with IPPs, this will involve identifying and exploring specific gas-fired capacity options and procurement processes, should they be needed.

The costs of advancing gas-fired generation over the next 24 months (F2013 and F2014) is approximately $750,000.\(^2^0\)

\(^2^0\) Short-term cost estimate pertains to acquisition process design without implementation.


Justification

As discussed in Chapter 6, there are two key drivers for advancing gas-fired generation:

1. To be able to meet additional LNG load development; and
2. To be a contingency resource.

Section 6.5 analyzed the supply options for LNG3 with and without additional mining load growth in the North Coast region over and above the loads included in the mid Load Forecast with Initial LNG. Two supply options were considered:

- System wide clean resource supply including pumped storage capacity in the Lower Mainland region supplied to LNG3 in Kitimat through the additional transmission lines; and
- Local clean resources backed up by local gas-fired generation (this option would not require the additional transmission lines).

In the analysis, it was identified that there was an incremental cost of system supply with pumped storage and new transmission lines, however, the difference was not large and would be mitigated if gas-fired generation was built in the system. In addition, the ultimate supply for LNG3 would be based upon customer preferences for supply including stability and reliability considerations. As discussed in section 6.10.3.4, pumped storage are uncertain and may not be available in the F2019 timeframe. Gas-fired generation may be the only viable supply option.

As discussed in section 6.10.6, under contingency conditions, incremental capacity could be required as early as F2016. As was concluded in section 6.10.7, gas-fired generation should be maintained for its optionality for contingency conditions.

As discussed in section 6.2.6, the costs of serving a Fort Nelson/HRB low load scenario (approximately 350 MW) based on a gas-fired generation strategy are
lower relative to a system-based clean energy strategy. BC Hydro may therefore
wish to preserve some of its 7 per cent non-clean head room to support supply Fort
Nelson load growth and electrification of the HRB.

**Execution**

BC Hydro will explore and develop a shelf-ready competitive procurement process to
select new 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, key risks, commercial and process issues to develop
a credible procurement framework that could be quickly activated if loads occur. As
part of the analysis, BC Hydro will also review other North American jurisdictions
where gas-fired capacity procurements have occurred in the last five to ten years.
The potential procurement process will 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, linking the development and operation of new gas-fired
resources with BC Hydro’s system, new clean energy supply and/or potential
transmission investments.

Given that little to no greenfield gas-fired generation project development work has
occurred in B.C. for decades, there are significant components in siting and
development of gas-fired generation facilities that need to be scoped. Depending on
the required lead times, BC Hydro may need to initiate procurement in F2015 to
maintain new gas 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 the work may occur in advance of any load commitments, BC Hydro will be open to sharing some of the cost of some of the work.

Risk Mitigation

The risks for this Recommended Action are:

- The contingency capacity option is not maintained and BC Hydro is unable to meet future load;
- BC Hydro incurs significant costs to advance these options and they are not required.

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.

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.

Future Approval Process

No approvals are required to explore natural gas-fired generation options and siting. If any energy supply contracts were entered into, the contracts would have to be filed with the BCUC under section 71 of the UCA. In addition, individual projects will likely be required to undergo provincial (BCEAA) environmental assessments,
depending on the size and characteristics of the individual projects, and will require
air emission permits pursuant to the B.C. *Environmental Management Act*.

### 9.4.4.4 Action 14. Monitor Fort Nelson/Horn River Basin Load and Supply

**Recommended Action:** Continue to monitor the northeast natural gas industry
and undertake studies to keep open electricity supply options, including
transmission connection to the integrated system and local gas-fired
generation.

In the current absence of load certainty or having customers willing to fund the work
in the Horn River Basin (HRB), it is premature to undertake significant supply actions
in the near term to address the potential for large-scale electrification in the region.
However, BC Hydro will continue to monitor natural gas industry developments in
the HRB and undertake studies to keep open supply alternatives, including
transmission connection to the system and local gas-fired generation.

BC Hydro has constructed scenarios that examine the oil and gas sector in the HRB
shale gas play, a potentially large load north of Fort Nelson that could require
electricity service from BC Hydro for gas extraction and transport. The HRB is an
immense resource whose viability will be significantly improved if its natural gas
production is used to supply LNG exports. More detailed discussion of this load
scenario is included in section 2.2.2.1.

In addition, BC Hydro must still plan for expected load growth in the Fort Nelson
region absent HRB electrification and will maintain the option for a second Fort
Nelson generating unit to supply load local to Fort Nelson only.

Expected costs for the monitoring, analysis and other activities related to maintaining
long-term supply options for serving Fort Nelson/HRB is approximately
$2 to 3 million. The majority of these costs relate to the following:
• Northeast Transmission Line (NETL) Study: Complete identification phase study. Approximately $600,000 to 750,000 has been spent in F2012 and $500,000 has been budgeted for F2013.

• Fort Nelson Expansion Project: Complete identification phase study to include local gas capacity additions. Estimated cost: $100,000 to $250,000.

• Fort Nelson remedial action scheme (RAS): In collaboration with Alberta Electric System Operator (AESO) design and implement a RAS that will allow BC Hydro to serve increased load on an interruptible basis until additional supply is added. Estimated Cost: $2 million.

**Justification**

In section 6.6 of the IRP, BC Hydro examines the electricity supply options for the Fort Nelson/HRB regions. The supply of electricity to the HRB is of interest to the government, gas producers and potential suppliers for economic development and GHG emissions reduction rationales.

The key supply alternatives are to interconnect the Fort Nelson/HRB with transmission and supply clean system power or to supply locally with gas-fired generation. A high efficiency cogeneration option may be an attractive thermal option.

The conclusions of this analysis are:

• A key requirement to make any Fort Nelson/HRB supply option feasible is obtaining load commitment;

• Supplying with clean energy is a higher cost solution, but does provide higher GHG reductions;

• Centralized thermal supply may have benefits over industry self-supply;
Industry, government and BC Hydro need to have a coordinated approach to supply in this region; and

BC Hydro needs to maintain local Fort Nelson supply options as a backup supply plan.

While there is no concrete supply option work in this situation, BC Hydro needs to advance the analysis and option development working proactively with the government and industry.

**Execution**

Key activities include:

- Continue to work with government to assess merits of HRB electrification with the Province’s economic development and GHG emission reduction objectives;
- Continue to work with potential HRB customers and private sector proponents to determine load requirements and explore options to supply this region;
- Complete technical feasibility, design and cost assessment of major transmission components supplying power to and within the HRB;
- Complete preliminary environmental and archeological assessment of major transmission and generation components;
- Consult with First Nations, as new information becomes available, to understand the potential effects of the supply alternatives to aboriginal/treaty interests; and
- Explore and develop a procurement process to select and advance new gas-fired generation projects in the region around Ft Nelson should it be required.
Risk Mitigation

The deployment speed of natural gas production and processing assets in the HRB (time to evaluate, commit, construct and place in service) is likely to be materially faster than BC Hydro’s ability to develop and deliver supply, leaving BC Hydro with making decisions ahead of industry, without commitments, or playing catch-up.

As a result, BC Hydro has played a relatively proactive role working with industry to assess the merits of providing electricity service to the HRB and its Recommended Action is consistent with this role, but without exposing the company to stranded investment risk.

In addition, BC Hydro will continue to rely on its existing 38.5 MW transmission service contract with Alberta to provide reliable back-up service to Fort Nelson region customers.

Future Approval Process

The Recommended Action does not require any approvals. If any transmission projects were proposed at a later date, regulatory (BCUC) and environmental assessment (BCEAA and CEAA) processes would be likely.

9.5 Additional IRP Recommendations

9.5.1 Province-Wide Electrification/Greenhouse Gas Reduction Initiatives

Section 6.7 addresses the potential implications of achieving government climate policy and CEAA climate-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 such as large compressors.

While the potential costs and impacts of general electrification can be significant, impacts in the near future are expected to be limited and need to be coordinated
with provincial climate change policy. In the interim, BC Hydro will undertake preparatory actions to ensure that it will be able to respond to future policy direction:

1. Continue to provide analysis and support to government to identify where electrification would be expected to occur in response to strong climate policy; and

2. 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.

3. As provided for in Recommended Actions 10 and 13, BC Hydro will explore development of new capacity resource options (pumped storage and natural gas) to prepare for new capacity requirements, should they emerge.

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

CEA objective 2(n) is “to be a net exporter of clean and renewable electricity while protecting the interests of persons who receive or may receive service in British Columbia,” which could occur by two different means:

- Exports that arise through the sale of surplus firm and non-firm energy associated with acquiring resources to meet domestic load self-sufficiency requirement;

- Exports that come through the acquisition of additional generation resources and investment in transmission for the purposes of selling electricity in the US over and above the self-sufficiency requirements.
The IRP export analysis considered the second category; that is, exports over and above those which are expected to occur under self-sufficiency. The key issues considered in the analysis are:

- The economic rationale for BC Hydro to pursue additional exports;
- BC Hydro’s decision to acquire additional generation in British Columbia for exports; and
- The need and benefit to continue to advance transmission projects needed to access export markets.

Chapter 7 provides a discussion on the export market opportunities and the current status of BC Hydro clean/renewable resources to meet these market opportunities. The key conclusion is that market conditions do not justify the development of new, additional resources for the export market into the foreseeable future. Since the conditions underpinning these market dynamics are expected to persist in the short to mid-term, BC Hydro anticipates no incremental expenditure 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 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 reduced environmental footprint. It is crucial to note that pre-building would not entail clearing or construction activities, but could include or be defined by the following activities:

- Identification of transmission routing;
- Right-of-way requirements;
- Line voltage, need for series and/or shunt compensation;
• Detailed study of possible alternatives;

• Design of the line, siting and design of the cluster’s central substation;

• Siting and design of series capacitor substation (if any); and

• Estimating the cost of project.

The details regarding cluster analysis are provided in section 6.9.4. The analysis pointed to the potential to somewhat reduce environmental footprints as a result of optimal transmission configurations, however 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 acquisition processes when projects in these cluster regions are being bid.

9.5.4 Geothermal

In Chapter 6, the IRP highlighted that there is a significant need for future capacity resources and that gas-fired generation is the default source of capacity until other capacity resources become more certain. Based on the 2010 Resource Options Report, geothermal has the potential to provide low cost energy as well as being a generation resource with high capacity value. However, the exploration and testing of sites to prove out the heat and energy potential is high cost and risky. In this IRP process, BC Hydro is extending its analysis to further understand the potential of geothermal resources, including the consideration of the resource’s economics and risk/reward structure, feasibility and the exploration and testing of sites to prove out the heat and energy potential for geothermal. Detailed discussions in the current developmental status of geothermal and the corresponding IRP analysis findings are provided in section 3.4.1.8 and section 6.8.4.12 respectively.

In view of BC Hydro’s significant need for future capacity resources, and the high resource potential, the consideration of geothermal will continue to be a key IRP
issue to BC Hydro. BC Hydro, in collaboration with the Provincial Government, will 
undertake necessary activities to review and assess the viability of geothermal 
generation in the province. This ongoing considerations include:

(i) Explore the opportunity to advance pilot projects;
(ii) Assess the viability of a mechanism to share development costs with potential 
developers;
(iii) Assess the potential impact of providing an up-front EPA for sites that prove to 
be commercially viable; and
(iv) Collaborate with the Ministry to ensure the regulatory issues are dealt with in 
lock-step with exploration and development activities.

9.6 Summary of IRP Recommended Actions Aligned with 
Clean Energy Act Objectives

Further to Table 1-1 in section 1.2.1.2, this section describes the detailed alignment 
of the IRP Recommended Actions with the CEA self-sufficiency requirement and 
other 15 energy objectives.

<table>
<thead>
<tr>
<th>CEA Energy Objectives</th>
<th>IRP Action Plan</th>
<th>Policy Alignment</th>
</tr>
</thead>
</table>
| (a) to achieve electricity self-sufficiency | The self-sufficiency requirement was adopted within the IRP as a required 
level of supply that has impacted all IRP Recommended Actions to either build resources or advance resources for potential future requirements. However, in some circumstances, BC Hydro has proposed bridging strategies to address short-term load/resource gaps and does not meet self-sufficiency requirements in every year. |
<table>
<thead>
<tr>
<th>CEA Energy Objectives</th>
<th>IRP Action Plan Recommended Action</th>
<th>Policy Alignment</th>
</tr>
</thead>
<tbody>
<tr>
<td>(b) to take demand-side measures and to conserve energy, including the objective of the authority reducing its expected increase in demand for electricity by the year 2020 by at least 66%;</td>
<td>Action 1: Pursue DSM Option 3</td>
<td>DSM Option 3 is all of the cost-effective DSM available at this time.</td>
</tr>
<tr>
<td></td>
<td>Action 2: Advance DSM Options 4 &amp; 5</td>
<td>DSM Option 3 achieves 58 per cent of incremental need with Initial LNG and 78 per cent without Initial LNG.</td>
</tr>
<tr>
<td>(c) to generate at least 93% of the electricity in British Columbia from clean or renewable resources and to build the infrastructure necessary to transmit that electricity;</td>
<td>Action 1: Pursue DSM Option 3</td>
<td>Advancing DSM Options 4 &amp; 5 may provide increased DSM savings in future IRPs.</td>
</tr>
<tr>
<td></td>
<td>Action 4: Continue to Pursue Site C</td>
<td>Pursuing a higher DSM target reduces the need for supply-side resources, which reduces the potential future need for additional gas-fired resources.</td>
</tr>
<tr>
<td></td>
<td>Action 9: Develop 2,000 GWh/year Clean Acquisition</td>
<td>Site C is a clean and renewable resource that provides clean energy and capacity. It also has the ability to shape, firm and help integrate further volumes of clean resources.</td>
</tr>
<tr>
<td></td>
<td>Action 5: Develop Revelstoke Unit 6</td>
<td>Provides clean resources to meet future electricity needs.</td>
</tr>
<tr>
<td></td>
<td>Action 7: Investigate and Advance Additional Resource Smart Projects</td>
<td>Developing clean capacity resources limits the need for new gas-fired generation.</td>
</tr>
<tr>
<td></td>
<td>Action 3: Pursue DSM Capacity Option</td>
<td></td>
</tr>
<tr>
<td></td>
<td>Action 11: New Transmission Infrastructure from Peace River to the North Coast</td>
<td>Adding a second 500 kV transmission line to the North Coast will allow system integration of renewables and reduce the amount of gas needed versus a North Coast only supply option.</td>
</tr>
<tr>
<td>CEA Energy Objectives</td>
<td>IRP Action Plan Recommended Action</td>
<td>Policy Alignment</td>
</tr>
<tr>
<td>-----------------------</td>
<td>-----------------------------------</td>
<td>-----------------</td>
</tr>
<tr>
<td>(d) to use and foster the development in British Columbia of innovative technologies that support energy conservation and efficiency and the use of clean or renewable resources;</td>
<td>Development of innovative technology in support of conservation and efficiency and the use of innovative technologies for clean or renewable resources will be addressed in the execution phases during acquisitions. DSM program development and the Technology Innovation supporting initiative contained within the DSM Implementation Plan focus on and promote the use of innovative technologies supporting energy conservation. The Standing Offer Program is open to all clean or renewable technologies.</td>
<td>The future acquisitions analyzed in the IRP and processes being developed as part of this action will ensure that the benefits of the Heritage Assets are accounted for.</td>
</tr>
<tr>
<td>(e) to ensure the authority's ratepayers receive the benefits of the heritage assets and to ensure the benefits of the heritage contract under the BC Hydro Public Power Legacy and Heritage Contract Act continue to accrue to the authority's ratepayers;</td>
<td>Action 9: Develop 2,000 GWh/year Clean Acquisition</td>
<td>Additional societal measures and codes and standards are expected to result in future low cost DSM.</td>
</tr>
<tr>
<td>(f) to ensure the authority's rates remain among the most competitive of rates charged by public utilities in North America;</td>
<td>Action 1: Pursue DSM Option 3</td>
<td>DSM is a least cost resource, albeit DSM Option 3 increases rates somewhat over DSM Option 2.</td>
</tr>
<tr>
<td></td>
<td>Action 2: Advance DSM Options 4 &amp; 5</td>
<td></td>
</tr>
<tr>
<td></td>
<td>Action 3: Pursue DSM Capacity Options</td>
<td>Capacity-focused DSM has the potential to deliver capacity savings over the long-term at a lower cost than other capacity resource options.</td>
</tr>
<tr>
<td></td>
<td>Action 4: Continue to Pursue Site C</td>
<td>Site C is a cost-effective resource for energy and capacity compared to alternative supply options.</td>
</tr>
<tr>
<td></td>
<td>Action 5: Develop Revelstoke Unit 6</td>
<td>Revelstoke Unit 6 is a cost-effective resource for dependable capacity compared to alternative supply options.</td>
</tr>
<tr>
<td></td>
<td>Action 6: Pursue Bridging Capacity from Existing Resources</td>
<td>Bridging is a flexible and cost-effective approach to meeting the short term capacity gap from F2016 to F2021.</td>
</tr>
<tr>
<td><em>CEA Energy Objectives</em></td>
<td><em>IRP Action Plan Recommended Action</em></td>
<td><em>Policy Alignment</em></td>
</tr>
<tr>
<td>-------------------------</td>
<td>-------------------------------------</td>
<td>-------------------</td>
</tr>
<tr>
<td>Action 7: Investigate and Advance Additional Resource Smart Projects</td>
<td>Resource Smart projects are cost-effective resources for dependable capacity compared to alternative supply options.</td>
<td></td>
</tr>
<tr>
<td>Action 8: Upgrade transmission from WSN to SKA</td>
<td>Upgrading the existing transmission lines with series compensation allows BC Hydro to utilize already contracted clean energy for supplying LNG facilities.</td>
<td></td>
</tr>
<tr>
<td>Action 9: Develop 2,000 GWh/year Clean Procurement Option</td>
<td>By acquiring a portion of the energy shortfall from F2017 to F2021 is a cost-effective trade-off of meeting self-sufficiency and rate payer impacts.</td>
<td></td>
</tr>
<tr>
<td>Action 11: New Transmission Infrastructure from Peace River to North Coast</td>
<td>New transmission infrastructure will only be considered when LNG3 load in forecast scenario meets critical forecast milestone.</td>
<td></td>
</tr>
<tr>
<td>Action 12: Develop Future Clean Procurement Options for LNG3</td>
<td>Acquisition for additional clean resources will only be launched when LNG3 load in forecast scenario meets critical forecast milestone.</td>
<td></td>
</tr>
<tr>
<td>Action 13: Explore Gas-Fired Contingency Capacity Options</td>
<td>The IRP recommends the most cost-effective resource selection in support of this objective to preserve gas-fired generation as default incremental capacity resource and for high value situations.</td>
<td></td>
</tr>
<tr>
<td>Action 14: Monitor Fort Nelson/HRB Load and Supply</td>
<td>The proposed approach eliminates the risk of stranded investment; however, integrating HRB may have rate impacts absent significant industry contributions.</td>
<td></td>
</tr>
<tr>
<td>Other Ongoing IRP Activities – General Electrification</td>
<td>BC Hydro will work with the government as the Climate Action Plan is implemented to ensure ratepayer costs are commensurate with other GHG emission reduction options.</td>
<td></td>
</tr>
<tr>
<td>Other Ongoing IRP Activities – Transmission advancement for generation clusters</td>
<td>Transmission advancement will be addressed during future acquisition processes to avoid potential for stranding costs and minimize ratepayer impacts.</td>
<td></td>
</tr>
</tbody>
</table>
### CEA Energy Objectives

<table>
<thead>
<tr>
<th>CEA Energy Objectives</th>
<th>IRP Action Plan Recommended Action</th>
<th>Policy Alignment</th>
</tr>
</thead>
<tbody>
<tr>
<td>(g) to reduce B.C. greenhouse gas emissions by 2012 and for each subsequent calendar year to at least 6% less than the level of those emissions in 2007, by 2016 and for each subsequent calendar year to at least 18% less than the level of those emissions in 2007, by 2020 and for each subsequent calendar year to at least 33% less than the level of those emissions in 2007, by 2050 and for each subsequent calendar year to at least 80% less than the level of those emissions in 2007, and by such other amounts as determined under the Greenhouse Gas Reduction Targets Act;</td>
<td>Action 1: Pursue DSM Option 3</td>
<td>DSM is a clean resource that provides energy and capacity avoiding need to consider further gas generation.</td>
</tr>
<tr>
<td></td>
<td>Action 2: Advance DSM Options 4 &amp; 5</td>
<td></td>
</tr>
<tr>
<td></td>
<td>Action 3: Pursue DSM Capacity Options</td>
<td></td>
</tr>
<tr>
<td></td>
<td>Action 9: Develop 2,000 GWh/year Clean Procurement Option</td>
<td>Removing gas as a base load energy option in favour of capacity and contingency needs and meeting 93% clean energy supports this objective.</td>
</tr>
<tr>
<td></td>
<td>Action 12: Develop Future Clean Procurement Options for LNG3</td>
<td>Working on methods to supply future LNG with clean resources.</td>
</tr>
<tr>
<td></td>
<td>Action 4: Continue to Pursue Site C</td>
<td>Site C is a clean and renewable resource that provides clean energy and capacity. It also has the ability to shape, firm and help integrate further volumes of clean resources.</td>
</tr>
<tr>
<td></td>
<td>Action 14: Evaluate Fort Nelson/Horn River Basin Load and Supply</td>
<td>BC Hydro is continuing to support government GHG reduction targets through advancement of electricity supply options to serve the Horn River Basin.</td>
</tr>
<tr>
<td></td>
<td>Other Ongoing IRP Activities – General Electrification</td>
<td>BC Hydro is continuing to support review and utilization of electrification in support of GHG reduction targets.</td>
</tr>
<tr>
<td>(h) to encourage the switching from one kind of energy source or use to another that decreases greenhouse gas emissions in British Columbia;</td>
<td>Action 9: Develop 2,000 GWh/year Clean Procurement Option</td>
<td>BC Hydro is working with Initial LNG producers to develop clean energy options to promote clean energy usage.</td>
</tr>
<tr>
<td></td>
<td>Action 8: Upgrade Transmission from WSN to SKA</td>
<td></td>
</tr>
<tr>
<td></td>
<td>Action 12: Develop Future Clean Procurement Options for LNG3</td>
<td>BC Hydro is working with future LNG proponents to develop clean energy options to promote clean energy usage.</td>
</tr>
</tbody>
</table>
### CEA Energy Objectives

| Action 11: New Transmission Infrastructure from Peace River to North Coast | Policy Alignment |
| Action 14: Evaluate Fort Nelson/Horn River Basin Load and Supply | BC Hydro is encouraging fuel switching to clean sources through advancement of the NETL or using efficient gas-based cogeneration as options to serve the HRB. |
| Other Ongoing IRP Activities – General Electrification | BC Hydro is continuing to support government fuel switching initiatives to decrease B.C. GHG emissions. |

(i) to encourage communities to reduce greenhouse gas emissions and use energy efficiently;

| Action 1: Pursue DSM Option 3 | DSM plans for savings from conservation and energy efficiency encourages the efficient use of energy and reduces the load. BC Hydro must serve with a related reduction in the need for thermal resources. |
| Action 2: Advance DSM Options 4 & 5 | |

Other Ongoing IRP Activities – General Electrification

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

| Action 9: Develop 2,000 GWh/year Clean Procurement Option | This objective will be addressed during the design of acquisition processes. The Standing Offer Program provides an option for small generation opportunities using innovative new technologies to obtain a supply contract. |
| Action 12: Develop Future Clean Procurement Options for LNG3 | |

---

**CEA Energy Objectives**

**Recommended Actions**

**IRP Action Plan**

**Policy Alignment**
### Chapter 9 - Recommended Actions

<table>
<thead>
<tr>
<th>CEA Energy Objectives</th>
<th>IRP Action Plan Recommended Action</th>
<th>Policy Alignment</th>
</tr>
</thead>
<tbody>
<tr>
<td>(k) to encourage economic development and the creation and retention of jobs;</td>
<td>All Recommended Actions</td>
<td>BC Hydro contributes to provincial economic development in three ways:</td>
</tr>
<tr>
<td></td>
<td></td>
<td>• Ensuring that an adequate infrastructure is in place to reliably,</td>
</tr>
<tr>
<td></td>
<td></td>
<td>securely and cost-effectively meet customers load requirements;</td>
</tr>
<tr>
<td></td>
<td></td>
<td>• Ensuring that the IRP recommendations are the most cost-effective supply of</td>
</tr>
<tr>
<td></td>
<td></td>
<td>resources within the requirements of the CEA;</td>
</tr>
<tr>
<td></td>
<td></td>
<td>• Consistent with the self-sufficiency requirement, providing that the</td>
</tr>
<tr>
<td></td>
<td></td>
<td>resources acquired from DSM, IPPs or for BC Hydro-owned infrastructure are</td>
</tr>
<tr>
<td></td>
<td></td>
<td>located within B.C..</td>
</tr>
<tr>
<td>(l) to foster the development of first nation and rural communities through the use</td>
<td>Action 9: Develop 2,000 GWh/year Clean Procurement Option</td>
<td>Power acquisition processes may provide opportunities for First Nations and rural</td>
</tr>
<tr>
<td>and development of clean or renewable resources;</td>
<td>Action 12: Develop Future Clean Procurement Options for LNG3</td>
<td>communities.</td>
</tr>
<tr>
<td>(m) to maximize the value, including the incremental value of the resources being</td>
<td>Action 10: Develop 2,000 GWh/year Clean Procurement Option</td>
<td>Incorporating impacts of various intermittent resources – such as wind</td>
</tr>
<tr>
<td>clean or renewable resources, of British Columbia’s generation and transmission assets</td>
<td>Action 12: Develop Future Clean Procurement Options for LNG3</td>
<td>integration and diversity factors or run-of-river freshet oversupply – in the</td>
</tr>
<tr>
<td>for the benefit of British Columbia;</td>
<td></td>
<td>power acquisition process ensures BC Hydro maximizes the value of B.C.’s</td>
</tr>
<tr>
<td></td>
<td></td>
<td>generation and transmission assets.</td>
</tr>
<tr>
<td></td>
<td>Action 4: Continue to Pursue Site C</td>
<td>Site C enhances the benefits of the existing Williston Reservoir by being the</td>
</tr>
<tr>
<td></td>
<td></td>
<td>third project on the Peace River system. Site C would generate 35 per cent of</td>
</tr>
<tr>
<td></td>
<td></td>
<td>the energy produced at the W.A.C. Bennett Dam with 5 per cent of the reservoir</td>
</tr>
<tr>
<td></td>
<td></td>
<td>area. Site C provides shaping, firming and integration benefits that will allow</td>
</tr>
<tr>
<td></td>
<td></td>
<td>BC Hydro to integrate additional clean energy resources.</td>
</tr>
<tr>
<td>CEA Energy Objectives</td>
<td>IRP Action Plan Recommended Action</td>
<td>Policy Alignment</td>
</tr>
<tr>
<td>--------------------------------------------------------------------------------------</td>
<td>-------------------------------------------------------------------------</td>
<td>---------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------</td>
</tr>
<tr>
<td>(n) to be a net exporter of electricity from clean or renewable resources with the intention of benefiting all British Columbians and reducing greenhouse gas emissions in regions in which British Columbia trades electricity while protecting the interests of persons who receive or may receive service in British Columbia;</td>
<td>Other Ongoing IRP Activities – Export Market Analysis</td>
<td>BC Hydro will continue to monitor the ongoing export market development; however, no specific Recommended Actions are made in this IRP's 10-year Action Plan.</td>
</tr>
<tr>
<td>(o) to achieve British Columbia's energy objectives without the use of nuclear power;</td>
<td>BC Hydro has removed nuclear power as an option to consider in the IRP.</td>
<td></td>
</tr>
<tr>
<td>(p) to ensure the Commission, under the Utilities Commission Act, continues to regulate the authority with respect to domestic rates but not with respect to expenditures for export, except as provided by this Act.</td>
<td>Other Ongoing IRP Activities – Export Market Analysis</td>
<td>BC Hydro will continue to monitor the ongoing export market development; however, no specific Recommended Actions are made in this IRP's 10-year Action Plan.</td>
</tr>
</tbody>
</table>