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December 23, 2008

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

Dear Ms. Hamilton:

RE: Project No. 3698514
British Columbia Utilities Commission (BCUC)
British Columbia Hydro and Power Authority (BC Hydro)
2008 Long-Term Acquisition Plan Application (2008 LTAP)

Enclosed as Exhibit B-1-11 is errata related to BC Hydro's revised Order sought as set out in Attachment 1 to the Evidentiary Update (Exhibit B-10) filed with the BCUC on December 22, 2008.

For further information, please contact the undersigned.

Yours sincerely,

Joanna Sofield
Chief Regulatory Officer

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c. BCUC Project No. 3698514 (2008 LTAP Application) Registered Intervenor Distribution List.
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Dear Ms. Hamilton:

RE: Project No. 3698514
British Columbia Utilities Commission (BCUC)
British Columbia Hydro and Power Authority (BC Hydro)
2008 Long Term Acquisition Plan (2008 LTAP)

Further to BC Hydro's letter of October 15, 2008 accompanying the filing of the non Fort Nelson-related second round Information Request (IR) responses, BC Hydro encloses the Fort Nelson evidentiary update (Exhibit B-1-10) and responses to Fort Nelson second round IRs (Exhibit B-4-2).

1. Fort Nelson Evidentiary Update

Exhibit B-1-10 updates the evidentiary record related to Fort Nelson, and is comprised of the following:

(1) Amendment of the Order sought with respect to the Fort Nelson Generating Station Upgrade (FNGU) as a result of updated cost estimates for FNGU. Refer to the revised Appendix A to the 2008 LTAP, and revised FNGU and Fort Nelson-related parts of Chapter 1 and 6 of the 2008 LTAP. The revised version of Appendix A supersedes prior versions of Appendix A (Exhibits B-1-1, B-1-5, B-1-6).

(2) Revised versions of Appendices N1 and N2, which supersede previous versions of these Appendices. Appendixes N1 and N2 have been revised to not only reflect the updated FNGU cost estimates, but also to address many of the issues raised by the Fort Nelson-related IRs. For example, as a result of several BCUC IRs, analyses of a 10 MW bioenergy plant and ~27 MW combined cycle gas turbine have resulted in additional Appendix N1 analysis. In addition, for ease of reference BC Hydro has consolidated and incorporated prior versions of Appendices N1 and N2 (Exhibits B-1-1, B-1-5, B-1-7, B-1-8) into the revised versions of Appendices N1 and N2 filed as Exhibit B-1-10.
2. Fort Nelson-Related IR Responses

BC Hydro encloses as Exhibit B-4-2 its responses to the following Fort Nelson-related Round 2 IRs.

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Consistent with established practice, BC Hydro requests that intervenors who have issues regarding the adequacy of responses to these IRs contact Craig Godsoe, BC Hydro counsel prior to taking any formal steps with the BCUC. Contact information for Craig Godsoe is: 604-623-4403 (telephone) and craig.godsoe@bchydro.com (e-mail).

Yours sincerely,

Joanna Sofield
Chief Regulatory Officer
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October 10, 2008

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

Dear Ms. Hamilton:

RE: Project No. 3698514
British Columbia Utilities Commission (BCUC)
British Columbia Hydro and Power Authority (BC Hydro)
2008 Long Term Acquisition Plan (2008 LTAP)

Attached as Exhibit B-1-9 is Errata to BC Hydro’s 2008 LTAP application.

Attached as Exhibit B-3-4 are revised responses to BCUC IRs 1.43.2 and 1.67.1.

The response to BCUC IR 1.43.2 has been revised to note that the Leadership in Energy and Environmental Design standard for new provincial government buildings may be mandated for new provincial government buildings but that such a requirement had not been established when Demand Side Management Options A and B were developed and thus was not included in Options A or B. The revised response to BCUC IR 1.43.2 replaces the original response to BCUC IR 1.43.2, filed as Exhibit B-3.

The response to BCUC 1.67.1 has been revised to reflect the Western Climate Initiative's (WCI) recent finalization of its "Design Recommendations for the WCI Regional Cap-and-Trade Program". The revised response to BCUC IR 1.67.1 replaces the original response to BCUC IR 1.67.1, filed as Exhibit B-3.

Yours sincerely,

Joanna Sofield
Chief Regulatory Officer
BC Hydro 2008 LTAP

ERRATA – October 10, 2008

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Joanna Sofield  
Chief Regulatory Officer  
Phone: (604) 623-4046  
Fax: (604) 623-4407  
regulatory.group@bchydro.com

September 5, 2008

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

Dear Ms. Hamilton:

RE: Project No. 3698514  
British Columbia Utilities Commission (BCUC)  
British Columbia Hydro and Power Authority (BC Hydro)  
2008 Long Term Acquisition Plan (2008 LTAP)

Attached as Exhibit B-1-8 is Errata No. 2 to BC Hydro’s 2008 LTAP.

Attached as Exhibit B-3-3 are revised responses to JIESC IRs 1.4.1 and 1.17.1.

For further information please contact the undersigned.

Yours sincerely,

Joanna Sofield  
Chief Regulatory Officer

Enclosures (2)

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August 19, 2008

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

Dear Ms. Hamilton:

RE: Project No. 3698514
British Columbia Utilities Commission
British Columbia Hydro and Power Authority (BC Hydro)
2008 Long-Term Acquisition Plan (2008 LTAP)

Enclosed as Exhibit B-1-6 is the amended Order sought by BC Hydro with respect to its 2008 LTAP. The amendments are reflected in changes to Chapters 1 and 6 of the 2008 LTAP, which are also attached.

For further information please contact the undersigned.

Yours sincerely,

Joanna Sofield
Chief Regulatory Officer

Enclosures
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July 4, 2008

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

Dear Ms. Hamilton:

RE: Project No. 3698514  
   British Columbia Utilities Commission (BCUC)  
   British Columbia Hydro and Power Authority (BC Hydro)  
   2008 Long Term Acquisition Plan (2008 LTAP)

Attached as Exhibit B-1-4 is Addendum to BC Hydro’s 2008 LTAP.

Attached as Exhibit B-1-5 is Errata to BC Hydro’s 2008 LTAP.

For further information please contact the undersigned.

Yours sincerely,

Joanna Sofield  
Chief Regulatory Officer

c. Project No. 3698514 Intervenors

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June 12, 2008

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

Dear Ms. Hamilton:

RE: British Columbia Utilities Commission (BCUC)  
British Columbia Hydro and Power Authority (BC Hydro)  
2008 Long Term Acquisition Plan (2008 LTAP)

Enclosed is BC Hydro's 2008 LTAP.

BC Hydro takes this opportunity to raise the following issues:

1. **Confidential Information:** As provided for in section 1 of the BCUC's *Confidential Filings Practice Directive (Practice Directive)*, BC Hydro requests confidential filing with the BCUC of a very limited amount of information concerning Columbia Power Corporation's (CPC) Waneta Expansion Project (WAX). BC Hydro, with CPC's full support, requests that the two Unit Energy Cost (UEC) numbers for WAX set out in section 3.3.10 of the 2008 LTAP remain confidential. The two UEC numbers for WAX are commercially sensitive information, particularly as the project is entering the Proposal Competition Stage of CPC's Request for Proposals for construction of the project. BC Hydro and CPC have consistently treated the UEC numbers for WAX as confidential. Public disclosure of the UEC numbers at this stage could have an adverse influence on the construction bids submitted. As required by section 1 of the *Practice Directive*, BC Hydro is serving copies of this letter on parties who have been invited to attend the 2008 LTAP workshops.

2. **LTAP Filing Cycle:** As set out in section 1.1.1 of the 2008 LTAP, BC Hydro proposes two modifications to the LTAP filing cycle.

   - First, BC Hydro proposes LTAP filing dates be made two years following receipt of the BCUC's decision on the previous LTAP application. The two year window following receipt of the next decision is required to provide BC Hydro sufficient time to consider the decision, undertake appropriate resource updates and planning studies and reflect the advancement of the Demand Side Management (DSM) initiatives set out in the DSM Plan. Given this two year timeline, the next LTAP would be expected to be filed in 2011.
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1.1 Application and Order Sought

This application is filed in support of British Columbia Hydro and Power Authority’s (BC Hydro) 2008 Long Term Acquisition Plan (2008 LTAP). The 2008 LTAP is both a primary driver in BC Hydro’s business processes and a regulatory requirement. As a business planning tool, the 2008 LTAP supports informed decision-making on resource procurement by providing an analytical framework for assessing resource investment trade-offs. The 2008 LTAP is BC Hydro’s first filing with the British Columbia Utilities Commission (BCUC) since the Utilities Commission Act (UCA) was amended by the Utilities Commission Amendment Act, 2008 (2008 UCA Amendments).¹ The 2008 LTAP is a “long term resource plan” within the meaning of sections 44.1(2) and 44.1(4) of the amended UCA.

In its 2008 LTAP, BC Hydro projects its future load requirements and compares them with existing and committed resource capabilities to determine the potential load/resource gap. BC Hydro also proposes solutions for filling the load/resource gap, and identifies the commitments it must make now, to ensure that it may continue to provide reliable, cost-effective service with manageable and reasonable risk² to its business and its customers over the next ten years (F2009 to F2019).

1.1.1 2008 LTAP Update and Planning Cycle

In its decision concerning BC Hydro’s 2006 Integrated Electricity Plan (IEP)/LTAP Application, the BCUC accepted BC Hydro’s proposal that it file a LTAP with the BCUC every two years.³ The IEP filings would accompany every second LTAP filing. LTAPs filed in years without an IEP would include updated information regarding changes to planning assumptions, inputs or scheduling that relate to the actions recommended in the previous LTAP.

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² The key uncertainties and their associated risks are discussed in section 5.2. Chapter 5 describes the different tools the 2008 LTAP uses to consider these key risks as they vary according to whether the risk impacts and probabilities can be quantified.
³ In the Matter of British Columbia Hydro and Power Authority’s 2006 Integrated Electricity Plan and 2006 Long-Term Acquisition Plan, Decision, May 11, 2007, page 42 (referred to as the 2006 IEP/LTAP Decision).

On a going-forward basis, BC Hydro proposes two modifications to the LTAP filing cycle. First, BC Hydro proposes LTAP filing dates be made two years following receipt of the BCUC’s decision on the previous LTAP application. The two year window following receipt of the next decision is required to provide BC Hydro sufficient time to consider the decision, undertake appropriate resource updates and planning studies and reflect the advancement of the Demand Side Management (DSM) initiatives set out in the DSM Plan found at Appendix K to this LTAP. Given this two year timeline, the next LTAP would be expected to be filed in 2011.

Second, BC Hydro proposes to eliminate the IEP/LTAP nomenclature and refer to all future long-term resource plans as LTAPs. To be clear, in proposing this modification, BC Hydro is not advocating for the elimination of an IEP-type analysis in future LTAPs. Rather than rigidly adhering to the view that LTAPs with an IEP analysis are required every four years, with LTAP updates required every two years, BC Hydro is of the view that whether future LTAPs to be filed every two years as described above are merely updates or entail more detailed analysis will turn on a number of factors, including changes to B.C. Government policy, the results of the proposed DSM Plan filed as part of this 2008 LTAP, or other issues that require significant First Nations and stakeholder input.

1.1.2 Order Sought

BC Hydro files the 2008 LTAP with the BCUC pursuant to subsections 44.1(2), 44.1(4) and 44.2(1) of the amended UCA, and applies for a BCUC Order which:

- Determines that the 2008 LTAP is in the public interest under subsection 44.1(6)(a) of the UCA. As part of this determination, BC Hydro requests that the BCUC endorse:
The residential Low Income DSM program, which has a Non-Participant Test (Ratepayer Impact Measure) benefit-cost ratio of 0.6 and an All Ratepayers Test (Total Resource Cost) benefit-cost ratio of 0.9. In BC Hydro’s submission the residential Low Income DSM program is not a tariff.

The rescission of Directives 62 and 64 of the BCUC’s decision concerning BC Hydro’s F2005/F2006 Revenue Requirements Application (F05/F06 RRA Decision).

The amendment of Directive 69 of the F05/F06 RRA Decision and Directive 16 of the 2006 IEP/LTAP Decision directing that DSM performance reports, as described in Directive 16, be filed with the BCUC on an annual basis.

The proposed Clean Power Call pre-attrition\(^4\) target of 5,000 GWh/year of firm energy;

The Clean Power Call eligibility requirement that the energy to be purchased pursuant to the Clean Power Call must qualify as “clean or renewable” in accordance with the B.C. Government’s Clean or Renewable Electricity Guidelines, a copy of which is attached as Appendix B3, and the other Clean Power Call eligibility requirements;

BC Hydro’s plan to rely on Burrard Thermal Generating Station (Burrard) for planning purposes for 900 megawatts (MW) of dependable capacity and 3,000 GWh/year of firm energy; and

BC Hydro’s amortization period for deferred DSM expenditures to remain at ten years; and

BC Hydro’s proposed capital plan review process including the review of major threshold projects and expenditures related to DSM.

• Determines that the following expenditures are in the public interest under subsection 44.2(3)(a) of the UCA:

• Expenditures of $418.0 million required to implement BC Hydro’s DSM Plan in F2009, F2010 and F2011;

\(^4\) When independent power producers (IPPs) that are awarded Electricity Purchase Agreements (EPAs) but do not ultimately develop and complete their projects (generally called attrition), or are deferred, BC Hydro must pursue other alternatives. See section 2.3.6 for the rate of attrition for past power procurement processes, and sections 6.2.6 and 6.2.7 for the proposed attrition allowance of 30 per cent for the Clean Power Call and the Bioenergy Call. The post-attrition volume of the Clean Power Call for planning purposes is 3,500 GWh/year.
Expenditures of $0.6 million in F2009 and F2010 required to undertake and complete the Definition phase work for capacity-related DSM initiatives;

Expenditures of $1.6 million of sustaining capital expenditures in F2010 required to ensure the reliability of Burrard;

Expenditures of $30.0 million required to undertake and complete the Definition phase work for Mica Unit 5 and Mica Unit 6 in F2009, F2010 and F2011;
Expenditures of $41.0 million required to undertake and complete the Stage 2 Definition and Consultation phase work for Site C in F2008, F2009 and F2010;

Expenditures of $2.0 million in F2009 and F2010 required to complete the Definition phase work, and to implement, the Clean Power Call; and

Expenditures required to complete the Definition phase work for, and Implementation phase of, the Fort Nelson Generating Station (FNG) Upgrade (FNGU) project (average annually increment of 24.6 MW (FNU3)). The current conceptual Feasibility phase estimate (+65 35 per cent/-35 15 per cent) for the FNG Upgrade (FNGU) FNU3 project is $59,140.1 million. The capital costs of the FNGU will be updated as part of an evidentiary update filed on or before Thursday, August 21, 2008, prior to the BCUC's second round of Information Requests (IRs). See section 1.3 for BC Hydro's proposal for the regulatory review of the 2008 LTAP.

In the alternative, should the BCUC deny the determination request for FNU3, BC Hydro seeks a determination that the expenditure of approximately $94.5 million (based on the current Feasibility phase estimate (+32 per cent/-15 per cent and schedule) to complete the Definition phase and Implementation phase of the Fort Nelson Generating Station Upgrade Case 2 (FNU2) is in the public interest under section 44.2(3)(a) of the UCA.

Approves the submission of the 2008 LTAP Contingency Resource Plans (CRPs) for inclusion in BC Hydro’s Network Integration Transmission Service (NITS) update. A draft Order is contained in Appendix A. Expenditures for F2009 and F2010, set out above, are consistent with the forecasts presented in BC Hydro’s F09/F10 Revenue Requirements Application (F09/F10 RRA) to be filed with the BCUC on June 30, 2008.

1.2 Context for Application

1.2.1 LTAP Update Process

BC Hydro developed the 2008 LTAP against a backdrop of continuing regulatory and market changes in the electric power industry, particularly in the areas of the B.C. Government’s policy and regulatory initiatives, and a North American wide promotion of renewable energy

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5 Due to the supply concerns in the Fort Nelson area, the FNGU is being fast tracked and as a result there is an increased risk to the FNGU schedule, scope and cost. The current conceptual phase estimate is subject to significant uncertainty and has a range from $38 million (-35 per cent) to $87 million (+65 per cent). Further engineering work is underway to complete feasibility design and prepare the Feasibility phase cost estimate with an estimate accuracy range of -15 per cent to +35 per cent. BC Hydro intends to file this updated estimated as part of the 2008 LTAP evidentiary update.

and greenhouse gas (GHG) reduction policies. These changes highlight the importance of understanding and accounting for the risks and uncertainties inherent in resource planning.

The 2008 LTAP planning process adapted the structured decision-analysis process undertaken for the 2006 IEP/LTAP. Figure 1-1 illustrates how the planning components were adapted in the 2008 LTAP compared with the 2006 IEP/LTAP. Many of the most significant updates to the input parameters are described in the remainder of this chapter.

In the 2006 IEP/LTAP Decision, the BCUC agreed with BC Hydro that “it has an obligation as a public utility to provide reliable, cost-effective electricity supply in an environmentally responsible manner, sufficient to meet customer demand and that this obligation should form the basis of its planning objectives”.\(^7\) As reflected in Figure 1-1, BC Hydro has not changed its planning objectives for the purposes of the 2008 LTAP.

Throughout the 2006 IEP/LTAP, there was recognition that reliability is a minimum constraint rather than an objective to be traded off against other objectives. BC Hydro has reflected this in its analysis by considering reliability to be a minimum constraint in much the same way as it treats legal requirements as minimum constraints.

\(^7\) Supra, note 3 at page 26.
There are two changes to the reliability criteria BC Hydro uses to evaluate when generation resources are required to maintain the reliable supply of electricity and to ensure that there are adequate resources available to meet its electricity supply obligations, both of which result from the B.C. Government’s Special Direction No. 10 (SD 10) to the BCUC:

- The 2,500 GWh/year non-firm market allowance has been removed from the 2008 LTAP energy load/resource balances after 2015. Refer to section 2.3.10; and
- The 400 MW market reliance has been removed from the capacity load/resource balances after 2015. Refer to section 2.3.10.

SD 10 is described below in section 1.2.3.

In advance of filing the 2008 LTAP, BC Hydro engaged First Nations and stakeholders in various forums that included Resource Options Update (ROU) public sessions, Intervenor workshops and general communication to the public. A report concerning the First Nations and stakeholder engagement process for the 2008 LTAP, the Clean Power Call, Mica Unit 5/Mica Unit 6, and Fort Nelson-related issues is found at Appendix Q.

1.2.2 BC Hydro’s Resource Needs Assessment

The 2008 LTAP analysis begins with an assessment of load growth, changes to supply and the resulting capacity and energy requirements. Within the planning horizon and without the 2008 LTAP action items, BC Hydro projects peak and energy resource deficits for the BC Hydro system beginning in F2012. Table 1-1 shows the annual capacity position (MW surplus or deficit) and annual energy position (GWh surplus or deficit).

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Chapter 2 explores the load/resource balance by first reviewing the 2007 Load Forecast, and then examining the existing and committed resources in the context of BC Hydro’s planning criteria.

1.2.3 B.C. Government Legislation and Policy


SD 10: One of the 2007 Energy Plan’s key Policy Actions – B.C. will be electricity self-sufficient by 2016 – has been given the force of law by a regulation made under the UCA. Section 3 of SD 10 directs the BCUC, in regulating BC Hydro, to use the criterion that BC Hydro is to achieve electricity self-sufficiency by 2016 and each year thereafter, and is to exceed self-sufficiency by at least 3,000 GWh/year as soon as practicable but no later than 2026. To become self-sufficient, BC Hydro will need to be able to acquire sufficient energy and capacity solely from electricity generating facilities within B.C. to allow it to meet its overall electricity supply obligations. For the purpose of evaluating BC Hydro’s supply portfolio, the BCUC is to assume critical water conditions, meaning that BC Hydro’s Heritage hydroelectric generating facilities contributed 42,600 GWh/year for planning purposes as of 2006. A copy of SD 10 is attached as Appendix B2.
The 2008 UCA Amendments were brought into force on May 1, 2008. Section 1 of the 2008 UCA Amendments adds the following five “government energy objectives”, which, pursuant to subsections 44.1(8) and 44.2(5) of the UCA, must be considered by the BCUC in determining whether to grant the requested BCUC Order:

- Encourage public utilities to reduce GHG emissions;
- Encourage public utilities to take demand-side measures;
- Encourage public utilities to produce, generate and acquire electricity from clean or renewable sources;
- Encourage public utilities to develop adequate energy transmission infrastructure and capacity in the time required to serve persons who receive or who may receive service from the public utility; and
- Encourage utilities to use innovative energy technologies (i) that facilitate electricity self-sufficiency or the fulfillment of their long-term transmission requirements; or (ii) that support energy conservation or efficiency or the use of clean or renewable sources of energy.

The 2008 LTAP aligns with the government energy objectives as set out in Table 1-2.

The 2008 UCA Amendments also introduced a new Part 3.1 to the UCA, entitled “Energy Security and the Environment”. Pursuant to section 64.01(1) of this new part of the UCA, BC Hydro must, by the 2016 calendar year, achieve electricity self-sufficiency in accordance with prescribed criteria. Additionally, under subsections 64.02(1) and 64.02(2), BC Hydro must “pursue actions” to “meet the prescribed targets in relation to clean or renewable resources, and must use the prescribed guidelines in planning for the construction or extension of generation facilities and energy purchases”. To date, no regulations have been passed prescribing criteria or targets for either section 64.01 or section 64.02.
<table>
<thead>
<tr>
<th>Policy Action</th>
<th>2008 UCA Amendment Reference</th>
<th>Section in Application</th>
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<tr>
<td>1 – Set an ambitious conservation target to acquire 50 per cent of BC Hydro’s incremental resource needs through conservation by 2020.</td>
<td>One of the “government’s energy objectives” in section 1 of the 2008 UCA Amendments is “to encourage public utilities to take [DSM] measures”. Section 44.1(4)(c) requires that BC Hydro include as part of its long-term resource plan filing with the BCUC a “statement of the [DSM] measures the authority would need to take so that, in combination with [DSM] measures taken by the government of British Columbia or of Canada or a local authority, the demand increase would be reduced by 50 per cent by 2020”.</td>
<td>Refer to the description of the DSM Plan in section 6.2.1 and Appendix K. The DSM Plan meets Policy Action No. 1 of the 2007 Energy Plan – BC Hydro will meet 78 per cent of its incremental resource needs through DSM by 2020. With respect to section 44.1(4) of the UCA, a statement of BC Hydro’s load in F2008 and forecast load in F2021 before DSM is provided in Table 2-1, section 2.2. With a DSM target of 11,500 for F2021, BC Hydro will meet 90 per cent of its incremental load growth between F2008 and F2021 through DSM.</td>
</tr>
<tr>
<td>3 – Encourage utilities to pursue cost-effective and competitive demand side management opportunities.</td>
<td>Section 44.1(2)(b) requires that BC Hydro include as part of its long-term plan filing with the BCUC a plan of how BC Hydro intends to reduce the demand for energy by taking cost-effective DSM measures.</td>
<td>Refer to the analysis in section 5.5, and the description of the DSM Plan in section 6.2.1 and Appendix K.</td>
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<tr>
<td>4 – Explore with B.C. Utilities new rate structures that encourage energy efficiency and conservation.</td>
<td>One of the “government’s energy objectives” in section 1 of the 2008 UCA Amendments is “to encourage public utilities to take [DSM] measures”. As defined in section 1, demand side measures include among other things a rate that either conserves energy or promotes energy efficiency or reduces the energy demand of a public utility or shifts the use of energy to periods of lower demand.</td>
<td>Rate structures form part of BC Hydro’s DSM Plan, as described in section 3.2.1.1 and Appendix K.</td>
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<td>Policy Action</td>
<td>2008 UCA Amendment Reference</td>
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<td>10 - Ensure self-sufficiency to meet electricity needs, including “insurance”.</td>
<td>SD 10, sections 1 and 3, described above.</td>
<td>SD 10 confirms that BC Hydro must be capable of meeting its overall energy supply obligations solely from electricity generating facilities in B.C. after 2015. The resource additions proposed in the 2008 LTAP assist BC Hydro in meeting this Policy Action. In addition, BC Hydro has: (1) removed the 2,500 GWh/year of non-firm energy/market allowance; and (2) the reliance on 400 MW from neighbouring jurisdictions, from its resource stack effective after 2015. Refer to section 2.3.10.</td>
</tr>
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<td>11 - Establish a standing offer for clean electricity projects up to 10 MW.</td>
<td>Parts of section 64.03 of the UCA.</td>
<td>BC Hydro’s Standing Offer Program (SOP) application was accepted by the BCUC on March 19, 2008 pursuant to BCUC Order No. G-43-08. The SOP was launched on April 11, 2008. Accordingly, 435 GWh/year of SOP energy and 39 MW of SOP capacity to be delivered during the two year review period have been included in BC Hydro’s supply resources. Refer to section 2.3.7.</td>
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<td>17 – Invest in upgrading and maintaining the heritage asset power plants and transmission lines to retain the ongoing competitive advantage these assets provide to the province.</td>
<td>Not applicable.</td>
<td>The analysis and requests in this 2008 LTAP include advancing Mica Unit 5 and Mica Unit 6 through the Definition phase of development. The 2008 LTAP also includes a request for approval of expenditures to complete the FNGU, a Resource Smart upgrade at the FNG. Refer to sections 6.2.4 and 6.2.9.</td>
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<tr>
<td>18 – All new electricity generation projects will have zero net GHG emissions.</td>
<td>One of the “government’s energy objectives” in section 1 of the 2008 UCA Amendments is “to encourage public utilities to reduce [GHG] emissions”. The Greenhouse Gas Reduction (Emissions Standards) Statutes Amendment Act, 20089 (Emissions Standards Act) amends the B.C. Environmental Management Act10 (EMA) to require all new electricity generating facilities and expansion to existing facilities using fossil fuels other than coal to have net zero GHG emissions as soon as the Emissions Standards Act comes into force.</td>
<td>The Emissions Standards Act is described in further detail in section 4.2. The proposed resource acquisitions set out in Chapter 6 of the 2008 LTAP are the least GHG intensive portfolio identified as being cost-effective. All new natural gas-fired generation is analyzed with zero net GHG emissions in the portfolio analysis in Chapter 5.</td>
</tr>
<tr>
<td>19 – Zero net GHG emissions from existing thermal generation power plants by 2016.</td>
<td>The Emissions Standards Act amends EMA to require all existing facilities using fossil fuels other than coal to have net zero GHG emissions by 2016.</td>
<td>See above in respect of Policy Action No. 18; all existing thermal was modelled in the portfolio analysis including the requirement to offset GHG emissions from 2016 onwards.</td>
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9 S.B.C. 2008, c.20. Given Royal Assent on May 29, 2008; the relevant part (section 2) in force by regulation. Refer to section 4.2 for additional details.

10 S.B.C. 2003, c.53.
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<td>20 – Require zero GHG emissions from any coal thermal electricity facilities.</td>
<td>The Emissions Standards Act amends EMA by requiring prescribed coal-fired generation facilities to capture and sequester GHG emissions from the combustion of coal.</td>
<td>See above in respect of Policy Action No. 18; BC Hydro examined the current status of coal-fired generation with carbon capture and sequestration (CCS) and concluded that coal-fired generation with CCS is not a commercial technology at this time. Refer to section 3.3.6 and Appendix F2.</td>
</tr>
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<td>21 – Ensure clean or renewable electricity generation continues to account for at least 90 per cent of total generation.</td>
<td>One of the “government’s energy objectives” in section 1 of the 2008 UCA Amendments is to “encourage public utilities to produce, generate and acquire electricity from clean or renewable resources”.</td>
<td>The energy to be purchased by BC Hydro under a Clean Power Call EPA must qualify as clean or renewable in accordance with the Clean or Renewable Electricity Guidelines; refer to section 6.2.6. BC Hydro is undertaking Stage 2 work on Site C, a potential third hydro-electric facility in the northeast region; refer to section 6.2.5.</td>
</tr>
<tr>
<td>22 – Government supports BC Hydro’s proposal to replace the firm energy supply from Burrard with other resources. BC Hydro may choose to retain Burrard for capacity purposes after 2014.</td>
<td>Not applicable.</td>
<td>BC Hydro is proposing that Burrard be maintained to reliably provide a capability of 900 MW (dependable capacity) and 3,000 GWh/year (firm energy) Refer to sections 2.3.2, 5.4 and 6.2.3.</td>
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<td>23 – No nuclear power.</td>
<td>Not applicable.</td>
<td>Nuclear technology is not eligible for the Clean Power Call; this restriction has been a consistent element of all recent BC Hydro power procurement processes. Refer to section 6.2.6.</td>
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<tr>
<td>Policy Action</td>
<td>2008 UCA Amendment Reference</td>
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<td>25 – Ensure the procurement of electricity appropriately recognizes the value of aggregated intermittent resources.</td>
<td>Not applicable.</td>
<td>Two interrelated issues are addressed in Appendix F12: (1) the capability attributed to individual intermittent resources; and (2) the aggregation value of a portfolio of intermittent resources. The result is a list of assumptions for capacity load/resource planning in the Chapter 5 portfolio analysis and for the transmission planning that underlies the 2008 LTAP analysis.</td>
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<tr>
<td>26 – Work with BC Hydro and parties involved to continue to improve the procurement process for electricity.</td>
<td>Section 1 of the 2008 UCA Amendments sets out the “government’s energy objectives” which are used to guide BC Hydro’s current power procurement processes.</td>
<td>BC Hydro consulted with First Nations, the B.C. Government and stakeholders in designing the SOP, Bioenergy Call and Clean Power Call. Appendix Q describes the engagement process for the Clean Power Call.</td>
</tr>
<tr>
<td>31 – Issue an expression of interest followed by a call for proposals for electricity from sawmill residues, logging debris, and beetle-killed timber to help mitigate the impacts from the provincial mountain pine beetle infestation.</td>
<td>Section 4 of SD 10 addresses the factors that are to guide the BCUC in considering a biomass EPA pursuant to subsection 71(2) of the UCA.</td>
<td>BC Hydro is planning a two-phase Bioenergy Call for power from generating plants located in B.C. that utilize sawmill residues, logging debris and beetle-killed timber as the fuel source. The Phase I Request for Proposals (RFP) was issued on February 6, 2008. Each of the two phases of the Bioenergy Call targets approximately 1,000 GWh/year of firm energy pre-attrition. Refer to section 6.2.7.</td>
</tr>
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</table>

1. **Amended Special Directives**: By Orders in Council No. 27 and 28 approved
2. January 17, 2008, the B.C. Government amended the definition of BC Hydro’s equity included in Special Directive No. HC1 to BC Hydro (HSD#1) and Special Direction No. HC2 to the BCUC (HSD#2). The amended HSD#2 deems BC Hydro’s equity for ratemaking.
purposes to be 30 per cent of the sum of BC Hydro’s average debt and average equity balances for the year. The capital structure and financial assumptions used to evaluate resource options and portfolios are further described in section 3.5. The amended HSD#1 and HSD#2 are included as Appendix B4.

1.2.4 BCUC 2006 IEP/LTAP Decision

BC Hydro’s planning is guided by decisions and regulatory orders issued by the BCUC, including the applicable BCUC directives in the 2006 IEP/LTAP Decision. Specifically, the 2008 LTAP:

- Addresses issues related to BC Hydro’s load forecasting. Refer to section 2.2.1;
- Addresses why BC Hydro proposes not to rely on 2,500 GWh/year of non-firm energy/market allowance beyond 2015. Refer to section 2.3.10;
- Addresses Burrard’s firm energy and dependable capacity contribution. Refer to section 2.3.2 and section 5.4;
- Will include a financial forecast of BC Hydro’s rates in both real and nominal terms for twenty years in a separate report to be filed with the BCUC in this proceeding either before or as part of BC Hydro’s responses to BCUC IR No. 1;
- Incorporates a review of a pumped storage hydro project on the Jordan River, and the Waneta Expansion Project (WAX), as part of the ROU. Refer to section 3.3 and Appendices F1 and F4; and
- Provides details on the progress made in the harmonization of transmission planning criteria used by BC Hydro and BCTC. Refer to Appendix F10.

Appendix C reproduces all 29 directives from the 2006 IEP/LTAP Decision along with a description of how and where, in this application, BC Hydro has addressed the applicable BCUC directives.
1 For purposes of the 2008 LTAP and consistent with the 2006 IEP/LTAP, BC Hydro continues to use the BCUC’s distinction between cost-effective and low cost. Competing projects/services/programs/initiatives are assessed based on a broad definition of cost-effectiveness, which in addition to cost includes: schedule/deliverability risk, reliability, timing, location and environmental impacts.¹¹

2.5 Other Relevant Government Policy and Regulatory Initiatives

GHG Policy and Regulation: In addition to the 2007 Energy Plan and the 2008 UCA Amendments, there has been a number of environmental policy and legislative developments that affect BC Hydro’s long-term resource planning. Since the 2006 IEP/LTAP, one of the primary issues emerging from government policy and regulatory initiatives is how to plan given an eventual, but highly uncertain, GHG regulatory regime. The Government of Canada, the B.C. Government and virtually every jurisdiction in the Western Electricity Co-ordinating Council (WECC)¹² have introduced, or are in the process of introducing, GHG regulatory regimes that profoundly alter the risk profile of fossil fuel-fired electricity generators. B.C. has joined Washington State, Oregon, California, Arizona, New Mexico, Utah, Montana, Manitoba and Quebec in the Western Climate Initiative (WCI) to develop a GHG cap-and-trade system, which would set a maximum level (cap) for GHG emissions. The United States (U.S.) Congress is also debating a number of GHG legislative proposals. BC Hydro retained an external expert to provide assistance in forecasting future GHG prices. In the analysis provided to BC Hydro, Natsource LLP (Natsource) concluded that there were no foreseeable policy scenarios in which GHG prices would be zero.

The B.C. Government’s 2008/09 – 2010/11 Budget and Fiscal Plan, the Carbon Tax Act ¹³, include a carbon tax of $10/tonne carbon dioxide equivalent (CO₂e) starting in July 2008 and increasing to $30/tonne CO₂e over a five year period. This new tax, which impacts the operating cost of generating stations fuelled by natural gas, was not reflected in the 2006


¹² WECC is comprised of B.C., Alberta, Washington State, Idaho, western Montana, Oregon, Wyoming, California, Nevada, Utah, Colorado, Arizona, most of New Mexico, small portions of Nebraska and South Dakota, and parts of northern Mexico.

IEP/LTAP and is reflected in the 2008 LTAP\(^{14}\). In addition, the forecast of GHG offset costs used in the 2008 LTAP has been updated from that in the 2006 IEP/LTAP. A comparison of the two forecasts is provided in Figure 1-2.

Figure 1-2 Comparison of GHG Offset Costs from the 2006 IEP/LTAP to the 2008 LTAP

Further details are provided in section 4.2 and the three Natsource GHG reports attached as Appendix G.

U.S. Renewable Energy Initiatives: Mandatory renewable portfolio standards (RPS) have been established in 25 U.S. states (including eight WECC states) and require electricity supply portfolios of utility providers to have an increased proportion of renewable resources. Qualifying resources differ by state, with small hydro (less than 30 MW) and wind electricity generating facilities qualifying in most WECC states. Most WECC states such as Oregon

\(^{14}\) Pursuant to section 84 of the Carbon Tax Act, the Provincial Government may exempt facilities from the carbon tax that are subject to GHG offset requirements. Refer to section 4.2 for additional details.
provide that Renewable Energy Credits (RECs)\(^\text{15}\) may be used to fulfill RPS targets if independently verified and tracked. Given that the proposed WCI GHG cap-and-trade system is only in the early stages of development, it is not clear how the system would interact with a RPS, particularly regarding the valuation of RECs.

BC Hydro retained Global Energy Decisions, Inc. (Global Energy) to provide an opinion as to the potential value of RECs in the future, and further, to assess the accessibility to a U.S. market for B.C.-based clean, renewable and low GHG electricity. In its analysis, Global Energy concluded that RPS goals would not be replaced by the WCI GHG cap-and-trade system. Global Energy further concluded that B.C.-based small hydro and wind electricity generating facilities would qualify to meet existing RPS goals in most U.S. states in WECC, provided that the renewable electricity they produced is registered with an acceptable renewable registry and tracking system such as the Western Renewable Energy Generation Information System (WREGIS). Refer to 4.5 and the Global Energy report entitled “Renewable Energy Credit – Market Analysis of Potential Renewable Energy Sales in WECC”, attached as Appendix H.

1.2.6 Power Industry Market Trends

**Natural Gas Price:** Another significant issue in resource planning is the prospect for long-term natural gas commodity price escalation and continued high volatility in gas prices. Natural gas price forecasts were prepared by Global Energy, utilizing three internally consistent, fundamentals-based scenarios of future market conditions it previously developed for the California Energy Commission (CEC) as part of the CEC Integrated Energy Policy Report (IEPR) process. The three natural gas price forecasts – referred to as 1B (Base), 2 (High) and 5BPlus (Low) – were selected because they cover a reasonably wide range of possible natural gas prices. In another improvement on the methodology BC Hydro applied in the 2006 IEP/LTAP, Global Energy was asked to assign probabilities to its three natural gas forecasts rather than assuming equal weighting. On the basis of its review, Global Energy assigned the following probabilities to its forecasts: 1B (Base) – 44 per cent; 2 (High) – 53 per cent; and 5BPlus (Low) – 3 per cent.

---

\(^{15}\) RECs are the separable renewable attribute associated with energy generated by renewable electricity sources. Typically, one REC equals one megawatt hour (MWh) of generation from a qualifying renewable electricity project.
BC Hydro’s forecast of natural gas prices as measured at Sumas Hub in the 2008 LTAP are based on Global Energy’s natural gas price forecasts. Figure 1-3 presents a comparison of the forecast natural gas prices in Canadian dollars used in the 2008 LTAP to that used in the 2006 IEP/LTAP.

Further details are provided in section 4.3 and Global Energy’s “Natural Gas Price Forecasts” report, attached as Appendix I.

**Market Price for Electricity at Mid-Columbia (Mid-C):** Electricity market prices are subject to similar variations to those seen in natural gas markets. Electricity prices for a large percentage of the hours of a year continue to be based on natural gas-fuelled generation. In the 2008 LTAP, the forecasts of market prices for electricity were based on the same Global Energy market forecasts that underpinned the above-mentioned natural gas prices.
1 BC Hydro’s forecast for market prices for electricity at Mid-C, measured in Canadian dollars, are compared to the forecast used in the 2006 IEP/LTAP in Figure 1-4.

**Figure 1-4** Comparison of Electricity Market Price Forecasts for Mid-C from the 2006 IEP/LTAP to the 2008 LTAP

Further details are provided in section 4.4.

**Resource Costs and Availability:** The 2008 LTAP also contains a ROU in Chapter 3 to reflect current information on the availability, cost and characteristics of specific resources that were updated because such resources were impacted by B.C. Government policies and/or their availability or costs have materially changed since the 2006 IEP/LTAP. The construction and heavy supply industries continue to experience real escalation in costs and scheduling.

**Transmission Constraints:** Transmission constraints, and the ability to address them in a timely manner, represent important planning considerations for ensuring that peak load obligations are met on a reliable basis. The most significant issue with respect to
transmission planning assumptions in the 2008 LTAP continues to be the concern for ensuring contingency plans are in place in the event the Interior to Lower Mainland (ILM) upgrade project (5L83) is not completed by its currently planned in-service date (ISD) of the fall of 2014.

An analysis of the load resource balance in the Lower Mainland /Vancouver Island (LM/VI) region is shown in Section 2.5.2. The implications of a delay in 5L83 ISD and BC Hydro’s related transmission contingency plans are presented in section 6.4.3.

In addition, BCTC participated in the 2008 LTAP by updating the cost information for potential transmission projects described in the ROU in Chapter 3 and conducting a high level analysis to determine the potential transmission upgrades that would be required for each portfolio examined in the 2008 LTAP. The 2008 LTAP proposes updated Base Resource Plan (BRP) and CRPs to inform transmission requirements over the next ten-year period.

1.3 Proposed Review and Approval Process

The BCUC’s role in reviewing long-term resource plans and related expenditure schedules is set out in sections 44.1 and 44.2 of the UCA. Subsection 44.1(5) of the UCA provides that the BCUC may establish a process to review a long-term resource plan filed under subsection 44.1(2).

BC Hydro is of the view that there are a number of issues in the 2008 LTAP Application that may potentially be resolved without a public hearing. BC Hydro does, however, believe that a public hearing will be necessary to consider other portions of this application.

As described in section 2.5.1 and Appendix N, there is insufficient capacity currently available to reliably meet customer demand in the Fort Nelson area. Currently there is a shortfall in supply of approximately 5 to 10 MW even without considering new load growth. As a result, 10 MW of the load in the region is being served as curtailable load. In recognition of this, BC Hydro proposes a preliminary process order establishing the following for the 2008 LTAP regulatory review:
• BC Hydro holds a DSM Plan half day technical workshop on Tuesday, June 24, 2008;

• BCUC IR No. 1 issued by Thursday, July 3, 2008;

• Intervenor IR No. 1 issued on Thursday, July 10, 2008;

• BC Hydro responses to BCUC and Intervenor IR No. 1 and BC Hydro’s long-term rate forecast report: Thursday, August 14, 2008;

• BC Hydro will endeavour to file a feasibility level (+35 per cent/-15 per cent) update to the capital cost estimate of the FNGU on or before Thursday, August 21, 2008;

• BCUC IR No. 2 issued on Wednesday, August 27, 2008;

• Intervenor IR No. 2 issued on Wednesday, September 3, 2008;

• BC Hydro responses to BCUC and Intervenor IR No. 2 on Wednesday, October 1, 2008.

After these two rounds of IRs, BC Hydro proposes a procedural conference on or about Friday, October 3, 2008 to consider further process issues, including consideration of whether the FNGU-related expenditure determination might be resolved through a written process.

1.4 Structure of Application

The application consists of six chapters and 18 appendices:

• Chapter 2 presents BC Hydro’s 2007 twenty year energy and peak load forecasts and compares them to existing and committed resources to establish the need for new resources.

• Chapter 3 sets out the ROU, which inventories and characterizes the demand-side and supply-side options that are commercially available to BC Hydro to meet future electricity requirements.
• **Chapter 4** sets out the GHG, natural gas and electricity price forecasts, and examines U.S. state RPS statutes and rules.

• **Chapter 5** describes how BC Hydro’s risk framework addresses key risk and uncertainties. Chapter 5 also describes the development of energy portfolios, and how the analysis of the cost and risks in the portfolio evaluation factored into BC Hydro’s preparation of the 2008 LTAP.

• **Chapter 6** sets out the 2008 LTAP programs, projects and acquisition processes that are needed to meet customer electricity needs arising from the analysis in Chapters 2, 3, 4 and 5. The 2008 LTAP contains two CRPs and a 5L83 transmission contingency plan.

The appendices to the application are:

• **Appendix A** contains a draft of the requested final Order.

• **Appendix B** contains the following B.C. Government policy and regulatory documents:
  
  ▶ The 2007 Energy Plan (B1);
  
  ▶ SD 10 (B2);
  
  ▶ *Clean or Renewable Electricity Guidelines* (B3); and
  
  ▶ Amended HSD#1 and HSD#2 (B4).

• **Appendix C** contains a table summarizing the 29 BCUC Directives arising out of the 2006 IEP/LTAP Decision along with the status of each relevant Directive and a reference to the section where the Directive is addressed in the 2008 LTAP.

• **Appendix D** is the 2007 Load Forecast.

• **Appendix E** is the Direct Testimony of Dr. Ren Orans of Energy and Environmental Economics, Inc. (E3) concerning the elasticity assumptions in the 2008 LTAP.

• **Appendix F** contains the following ROU-related documents:
  
  ▶ Resource Options Database (*RODAT*) sheets (F1);
The Powertech Labs Inc. (Powertech) Technology Summary Clean Coal Power Generation by CO₂ Sequestration; (F2);

BC Hydro’s wind integration cost assessment (F3);

The BC Hydro Engineering report concerning Jordan River pumped storage (F4a);

Powertech evaluation of the Jorvic Sewage Reclalm Pipeline at BC Hydro’s Jordan River Hydroelectric Project (F4b);

The Kerr Wood Leidal Associates Ltd. (Kerr Wood) Run-of-River Resource Assessment for B.C. (F5);

The Garrad Hassan Canada Inc. (GH) Assessment of the Energy Potential and Estimated Costs in B.C of Wind Energy (F6);

The AMEC Americas Limited (AMEC) Gas-Fired Combustion Turbine Power Plant Costs and Performance Update report (F7);

Potential Large Hydro Project report (F8);

Integrated System (transmission) Planning Assumptions (F9);

Calculation of Capacity Planning Reserves as filed in the 2007 Alcan EPA proceeding (F10);

Estimated Unit Energy Cost (UEC) Cost Adjustment Values (F11);

Effective Load Carrying Capability (ELCC) Firm Energy Load Carrying Capability (FELCC) of Intermittent Resources report (F12);

Comparison of the 2008 ROU to the 2006 Call (F13);

The Risk Framework Explanation and Applications (F14);

Resource Planning Models (F15);

Portfolios and Analysis (F16); and
DSM Resource Options (F17);

- **Appendix G** contains the three Natsource GHG price forecast-related reports, as follows:
  - The 2007 GHG Offset Forecast Report (G1);
  - An addendum to G1 to address the B.C. carbon tax (G2); and
  - Natsource’s memorandum estimating the probability of the main GHG scenarios (G3).


- **Appendix I** contains Global Energy’s Natural Gas Price Forecast for BC Hydro report.

- **Appendix J** contains four Burrard-related reports, as follows:
  - AMEC’s Condition Assessment and Alternative Configuration Study-Burrard Generating Station:
    - Current Configuration (J1); and
    - Alternative Configuration (J2);
  - RWDI Air Inc.’s (RWDI):
    - Burrard Consent to Operate Risk Analysis (J3); and
    - Permitting Requirements for Rebuilding Burrard Thermal Generating Station (J4).

- **Appendix K** is BC Hydro’s DSM Plan.

- **Appendix L** contains two Site C-related reports:
  - Summary: Stage 1 Review of Project Feasibility report (L1); and
  - The Stage 2: Project Definition and Consultation plan (L2).

- **Appendix M** contains a copy of the Clean Power Call Request for Proposals (RFP).
Introduction and Context

1. **Appendix N** contains:
   
   ▪ The Fort Nelson Resource Plan-Related and Long Term Acquisition Plan (N1); and
   
   ▪ The FNGU Report (N2).

2. **Appendix O** contains BC Hydro’s Base Plan and CRPs (O1).

3. **Appendix P** contains the Assessment of Puget Sound Area/Northern Intertie Curtailment Risk report.

4. **Appendix Q** contains the First Nations and stakeholder engagement report for the 2008 LTAP, the Clean Power Call, Mica Unit 5 and Mica Unit 6, Fort Nelson-related issues, and the draft Application workshop presentation and intervenor comments.

5. **Appendix R** is the Glossary and Abbreviations.
LOAD AND RESOURCE BALANCE
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2.1 Introduction

Step two (see Figure 1-1) in this 2008 LTAP is to establish the load/resource balance. In this chapter BC Hydro presents its 2007 Load Forecast over the next twenty years and compares it to existing and committed resources to establish the need for new resources. Section 2.2 reviews the 2007 Load Forecast, and section 2.3 examines the existing and committed resources in the context of BC Hydro’s planning criteria, recent BCUC decisions, SD 10 and the 2007 Energy Plan. The load/resource balance is considered in section 2.4. Section 2.5 reviews the load/resource balances in the two regions that are of particular importance to the 2008 LTAP analysis, namely the Fort Nelson area and the LM/VI region.

2.2 BC Hydro 2007 Load Forecast Characteristics, Methodology and Trends

This section presents BC Hydro’s 2007 Total Load Forecasts (both energy and peak) including a breakdown of the Total Load Forecast into BC Hydro’s forecast obligations in the Integrated System, Fort Nelson and the Non-Integrated Areas (NIAs). Refer to Table 2-1. The 2007 Total Load Forecast presented in this Chapter excludes the impact of any savings from incremental DSM initiatives. The forecast does include the impact of a forecast of future rate increases on the Load Forecasts, as per Directive No. 17 from the 2006 IEP/LTAP Decision. The 2008 LTAP, and in particular the portfolio analysis in Chapter 5 and the action items set out in Chapter 6, are based on the 2007 Load Forecast inclusive of the impacts of rate increases. The effect on load due to changes in rate structures are reported in the DSM Plan attached as Appendix K.

---

16 NIAs are not interconnected to the main electric system. The areas included in the NIAs sales forecast are Masset, Sandspit, Atlin, Dease Lake, Eddontenajon, Telegraph Creek, Anahim Lake, Bella-Bella, and Bell Coola.
Table 2-1  Key Characteristics of the 2007 Load Forecast Before DSM

<table>
<thead>
<tr>
<th>Energy Load (GWh/year)</th>
<th>F2008</th>
<th>F2021</th>
<th>F2027</th>
<th>Change from F2008 – F2027</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td></td>
<td></td>
<td></td>
<td>Total Per cent Change</td>
</tr>
<tr>
<td>Integrated System</td>
<td>58,366</td>
<td>71,079</td>
<td>76,778</td>
<td>31.5</td>
</tr>
<tr>
<td>Fort Nelson</td>
<td>206</td>
<td>287</td>
<td>305</td>
<td>47.8</td>
</tr>
<tr>
<td>NIA</td>
<td>128</td>
<td>139</td>
<td>143</td>
<td>11.6</td>
</tr>
<tr>
<td>Total</td>
<td>58,700</td>
<td>71,505</td>
<td>77,225</td>
<td>31.6</td>
</tr>
</tbody>
</table>

This 2008 LTAP does not include plans for the NIAs. Each NIA is an isolated region with its own load/resource balance. The load/resource balances for NIA’s are planned and managed on a case by case basis. Therefore, the NIA is not referenced nor are the energy requirements included in any calculations for the remainder of this 2008 LTAP Application document. A resource plan for Fort Nelson is included in this 2008 LTAP as a separate plan. Refer to section 6.2.9 and Appendix N of this Application.

2.2.1  2007 Load Forecast Methodology Overview

BC Hydro’s load forecasting methodology was the subject of extensive review in the 2006 IEP/LTAP proceeding. In its 2006 IEP/LTAP Decision, the BCUC found that “BC Hydro’s load forecast has generally been prepared in accordance with the [BCUC’s] Guidelines and accepts that the results of the 20-year forecast are reasonable for purposes of the 2006 IEP/LTAP”. BC Hydro incorporates relatively certain loads and demand trends into its forecast. Potential loads such as electric plug-in vehicles (EPVs) have not specifically been factored into the Load Forecast underpinning the 2008 LTAP. BC Hydro is closely monitoring technological trends such as EPVs for possible future inclusion into the base forecast. Similarly, with respect to the possibility of load reductions due to industrial customer attrition, BC Hydro includes into its forecast verifiable information regarding specific customer loads. The closure assumption concerning Highland Valley Copper, for example, is based on public domain information provided by the customer.

17 2006 IEP/LTAP Decision, page 52.
Since the 2006 IEP/LTAP Decision, changes to the load forecasting methodology fall into two categories:

- Some specific changes have been made to the 2007 Load Forecast to address the load forecasting Directives in the 2006 IEP/LTAP Decision. Actions taken in response to these Directives are summarized in Table 2-2 and Table 2-3 below.

- Relative to the 2006 Load Forecast, changes to the forecast methodology have primarily occurred in the industrial sector. The key change to this forecast involves the incorporation of consultant information into customer forecasts. Refer to section 2.2.4 for further details. The methodologies for producing the peak forecast, and the forecasts for the residential and commercial sectors, are substantially the same for the 2007 Load Forecast.

Appendix D, BC Hydro’s 2007 Annual Load Forecast document, provides additional details on methodologies and includes the 2007 Load Forecasts before DSM with and without the impacts of the forecast of future rate levels.

Table 2-2  BCUC 2006 IEP/LTAP Decision Directives and BC Hydro Actions

<table>
<thead>
<tr>
<th>Directive</th>
<th>Action</th>
</tr>
</thead>
<tbody>
<tr>
<td>3. The BCUC Panel directs BC Hydro to include with its next load forecast a report assessing if there are statistically quantifiable trends associated with the temperature metrics used to forecast peak and energy demands, and an analysis of whether these trends should be extrapolated or otherwise incorporated for use in predicting peak and energy usage in the future. Whether BC Hydro determines it should continue to use temperatures based on historical averages or a statistical trend for forecasting peak and energy demand, the Commission Panel expects BC Hydro to provide a clear and consistent rationale for the historical period it uses for calculating averages, estimating trends, or evaluating variability.</td>
<td>Appendix 1B of the 2007 Load Forecast, attached as Appendix D, contains a response to this Directive. BC Hydro analysis indicates that a 10-year rolling average of degree days is the best representation of weather for forecasting energy sales. In addition, a rolling 30-year period of the coldest daily average temperature is an appropriate method for forecasting peak demand.</td>
</tr>
<tr>
<td>4. The BCUC Panel accepts BC Hydro’s undertaking to provide adjustments to a load forecast within the updated forecast, and in a manner that provides an explanation of the adjustments and reconciliation to the load forecast.</td>
<td>Appendix A1.3 to the 2007 Load Forecast discusses adjustments to the forecasts.</td>
</tr>
</tbody>
</table>
Directive | Action
---|---
5. Subject to the issues noted above and in Sections 3.2.4 and 6.1.2, the BCUC Panel finds that BC Hydro’s load forecast has generally been prepared in accordance with the BCUC’s Guidelines and further accepts that the results of the 20-year forecast are reasonable for the purposes of the 2006 IEP/LTAP. At the time of filing its next annual load forecast, the BCUC Panel directs BC Hydro to provide a review of its prospective forecast range as produced by the Monte Carlo simulation, relative to its historical experience. | Section 5 of the 2007 Load Forecast discusses the historical accuracy of previous forecasts in context of the ranges of the 2007 Load Forecast as produced by the Monte Carlo simulation. In Appendix 2 to the 2007 Load Forecast, BC Hydro concludes that the Forecast ranges as produced by the Monte Carlo are a reasonable representation of the range of expected variability around the Forecast.

1 In addition to the above Directives, other Directives and issues raised in the 2006 IEP/LTAP Decision impact the 2007 Load Forecast, as set out in Table 2-3.

2 Table 2-3 Other Issues and Directives raised in the 2006 IEP/LTAP Decision Impacting the 2007 Load Forecast

<table>
<thead>
<tr>
<th>Issues or Directives</th>
<th>Action</th>
</tr>
</thead>
<tbody>
<tr>
<td>17. The BCUC’s determination in section 6.2 of the Decision directed BC Hydro to file financial forecast of BC Hydro’s rates in both real and nominal terms, for a minimum of ten years, but preferably 20 years. The BCUC Panel further directs BC Hydro to rely on the report for assumptions regarding retail prices in each of the Conservation Potential Review (CPR), the load forecast, and DSM evaluation methodologies.</td>
<td>The 2007 Reference Load Forecast reflects the impact of a long term rate forecast. The 2007 Reference Load Forecast also reflects the impacts of interim rates as filed by BC Hydro in its F09/F10 RRA. This rate impact calculation assumes current rate structures are unchanged. Incremental load savings due to changes in rate structure are reported in the DSM Plan attached as Appendix K to the 2008 LTAP.</td>
</tr>
<tr>
<td>In the BCUC Panel’s view BC Hydro should improve the presentation of its transmission level industrial forecast by providing an explanation of the value that is added to the forecast by the consideration of consultant reports in the three industrial sectors discussed when they apparently do not change the “envelope” forecast resulting from the econometric analysis. The BCUC Panel expects BC Hydro to justify the expense of the exercise of attributing load to individual customers, when its next load forecast is filed.</td>
<td>Modifications to the industrial forecast methodology have been undertaken. These are the result of incorporation of AMEC’s report on B.C.’s forestry sector. BC Hydro is of the view that a bottom-up forecast (i.e., attributing load to individual customers) enhances the forecasting process.</td>
</tr>
</tbody>
</table>
## Issues or Directives

<table>
<thead>
<tr>
<th>Action</th>
</tr>
</thead>
<tbody>
<tr>
<td>Appendix A1.3 of the 2007 Load Forecast presents adjustments to the</td>
</tr>
<tr>
<td>Forecast. BC Hydro incorporates Forecast adjustments for specific</td>
</tr>
<tr>
<td>large industrial loads (such as Highland Valley Copper) as the</td>
</tr>
<tr>
<td>contribution to demand is disproportionally larger than their</td>
</tr>
<tr>
<td>contribution to forecast drivers such as GDP.</td>
</tr>
<tr>
<td>The BCUC Panel does not believe that there is added value to</td>
</tr>
<tr>
<td>including a forecast of billed sales in load forecasts. While the</td>
</tr>
<tr>
<td>BCUC Panel agrees that the enhanced accuracy may be small, it believes</td>
</tr>
<tr>
<td>that providing a forecast that includes the accrual will enhance</td>
</tr>
<tr>
<td>transparency and provide information on a consistent basis for both</td>
</tr>
<tr>
<td>future IEP/LTAP and RRA Applications.</td>
</tr>
<tr>
<td>BC Hydro continues to publish an annual forecast based on billed</td>
</tr>
<tr>
<td>sales because: (i) the difference between billed and accrued sales</td>
</tr>
<tr>
<td>is relatively small; (ii) billed sales are readily available by all</td>
</tr>
<tr>
<td>rate classes as such forecasting models can easily be updated using</td>
</tr>
<tr>
<td>billed sales; and (iii) modifications to existing forecasting process</td>
</tr>
<tr>
<td>to include accrued sales would involve extensive computations to</td>
</tr>
<tr>
<td>develop a revised history.</td>
</tr>
</tbody>
</table>

## Key Trends – 2007 Energy Load Forecast

- **Residential:** Sales to the residential sector, before weather adjustment, grew by 612 GWh or 3.8 per cent from F2006 to F2007, and on a weather-normalized basis, grew by 164 GWh or 1.0 per cent. Sales are expected to grow more slowly relative to the previous Load Forecast over the near-term. This reflects a slower projection in use rate and housing starts. Over the long term, sales recover above last year’s 2006 Forecast reflecting a higher forecast in housing starts. Please refer to Table 2-4 for the sales forecast before DSM and including projected rate level impacts. A comparison of the 2007 Load Forecast to the 2006 Load Forecast is provided in section 2.2.4.

- **Commercial:** Electricity consumption of the commercial sector can vary considerably from year to year reflecting the level of activity in B.C.’s service sector. Sales to BC Hydro’s commercial sector grew by 384 GWh or 2.6 per cent between F2006 and F2007. This growth reflects the strong performance of the B.C. economy. The current Forecast is projected to be above the 2006 Load Forecast, reflecting the expected strong performance in the goods and services part of the economy. Please refer to Table 2-4.
1. **Industrial**: Electricity consumption in the industrial sector is quite volatile, driven substantially by economic conditions in the U.S., China and Japan, and events that affect commodity markets. Sales to BC Hydro’s industrial sector declined by 467 GWh or 2.3 per cent between F2006 and F2007. The industrial forecast is below last year’s Forecast both in the near term and the long term. The 2007 Load Forecast reflects the impact on recent trends such as an appreciation in the Canadian dollar, a slow down in the U.S. housing starts and lower demand for pulp and paper. In the medium to long-term, the forecast reflects the expected impact of the pine beetle infestation, which is anticipated to slow production and investment in both sawmills and pulp mills. Please refer to Table 2-4.

<table>
<thead>
<tr>
<th>Energy Load (GWh/year)</th>
<th>F2008</th>
<th>F2021</th>
<th>F2027</th>
<th>Change from F2008 – F2027</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td></td>
<td></td>
<td></td>
<td>Total Per cent Change</td>
</tr>
<tr>
<td>Residential</td>
<td>17,087</td>
<td>22,133</td>
<td>24,429</td>
<td>43.0</td>
</tr>
<tr>
<td>Commercial</td>
<td>15,621</td>
<td>20,743</td>
<td>23,119</td>
<td>48.0</td>
</tr>
<tr>
<td>Industrial</td>
<td>19,016</td>
<td>20,040</td>
<td>20,437</td>
<td>7.5</td>
</tr>
<tr>
<td>Domestic Sales</td>
<td>53,093</td>
<td>64,669</td>
<td>69,827</td>
<td>31.5</td>
</tr>
<tr>
<td>Total Integrated</td>
<td>58,366</td>
<td>71,079</td>
<td>76,778</td>
<td>31.5</td>
</tr>
<tr>
<td>Peak Demand (MW)</td>
<td>10,783</td>
<td>12,458</td>
<td>13,433</td>
<td>24.6</td>
</tr>
</tbody>
</table>

2.2.3 **Key Trends – Peak Load Forecast**

BC Hydro’s total peak demand grew, after weather adjustments, by 319 MW or 3.1 per cent between F2006 and F2007. Over this time period, there was strong growth in the distribution peak and a decline in growth in the transmission peak demand. For the 2007 Load Forecast period, the distribution peak remains relatively strong, while growth in transmission peak has been reduced. The growth in the distribution peak reflects growth in drivers of housing, employment and other infrastructures that impact substation demands, including Olympic facilities. The reduced growth in transmission peak demand primarily reflects reduced demand from larger customers in the pulp and paper sector.
The total integrated peak demand before DSM and including projected rate level impacts is expected to grow by 1.5 per cent over the next five years, 1.3 per cent over the next 11 years and 1.3 per cent over the next 21 years.

In the short term (i.e., the first five years of the forecast) the forecast average annual peak demand compound growth rate is 1.5 per cent, which is 0.1 per higher than the forecast growth rate in integrated system energy requirements. The somewhat higher growth in the peak reflects growth in economic drivers such as housing starts, employment and large discrete infrastructure projects (such as Olympics and transportation infrastructure) which impact individual substation demands. The updated peak forecast also reflects increases in actual system peak loads in F2006 and F2007. In the medium term (i.e., next 11 years) and long term (21 year term), the average growth rate in the total energy requirements is above the peak demand by 0.4 per cent and 0.2 per cent respectively. In this period, there are fewer large distribution projects incorporated into the forecast. In addition, over this timeframe, the forecast transmission peak reflects reductions in forestry sector requirements.

2.2.4 Comparison to the 2006 Load Forecast

The 2007 Load Forecast for BC Hydro’s Integrated System is lower than the 2006 Load Forecast in both long-term peak and energy requirements; refer to Figure 2-1 and Figure 2-2 below. The primary reasons for the lower 2007 Load Forecast relative to the 2006 Load Forecast are:

- Lower Historical Sales – For the residential and industrial sales forecasts, compared to the 2006 Load Forecast 2006/07 billed sales, sales were 1.1 per cent lower than forecast in the residential sector and 3.1 per cent lower than forecast in the industrial sector. This year’s forecast starts from a lower point than projected in the 2006 Load Forecast.

- Industrial load – The industrial sector represents 37 per cent of BC Hydro’s domestic electricity sales, and the forestry sector represents 60 per cent of the industrial sector. While residential and commercial customer segments have been relatively stable in terms of historic load and projected future loads, BC Hydro’s industrial sector load has been more variable in the past due to economic cycles, commodity prices and labour
disruptions. Since the 2006 Load Forecast, developments in the metals/mining (such as the removal of the proposed Kemess North mine\textsuperscript{18}) and forestry sectors have caused downward revisions to the industrial load. Revisions to industrial forestry sector reflect recent trends such as lower sales due to a high Canadian dollar, low lumber prices and declining U.S housing starts and the medium to long-term trends of diminished lumber production and pulp product. Production forecasts from a forestry study prepared by AMEC for BC Hydro in August 2007 were incorporated into the 2007 Load Forecast.

\begin{itemize}
\item Impacts from rate increases (elasticity effect) – The 2007 Load Forecast incorporates proposed rate increases from the F09/F10 RRA plus a forecast of long-term rate increases. The resulting overall long-term decrease in the 2007 Load Forecast, before DSM and rate structure changes, is in the range of 800 GWh/year for F2016 increasing to 1,000 GWh/year by F2025 using an elasticity of -0.05.\textsuperscript{19} The elasticity assumptions are described in Appendix E.
\end{itemize}

\textsuperscript{18} On September 17, 2007 the Joint Panel conducting an environmental assessment of the Kemess North mine recommended that the B.C. and Federal Governments not allow the mine to proceed. The Joint Panel’s recommendation was accept by both Governments. The removal of Kemess North expansion project from the 2007 Load Forecast reduced the Forecast by 500 GWh/year starting in F2011.

\textsuperscript{19} Elasticity measures the responsiveness of buyers to changes in electricity prices. A consumer who is sensitive to price changes has a relatively elastic demand profile. A customer who is unresponsive to price changes has a relatively inelastic demand profile.
2.2.5 Key Uncertainties

BC Hydro uses a Monte Carlo model to estimate the uncertainty of BC Hydro’s Load Forecast. Details on the Monte Carlo model are found in Appendix 2 of Appendix D. This model produces a forecast uncertainty band around the Reference or Mid Load Forecasts by examining the impact on load of the uncertainty in a set of key drivers including economic activity, weather, electricity rates and elasticities. The uncertainty bands include:
• A low band: There is a 10 per cent chance the outcome will be below this value.

• A high band: There is a 10 per cent chance that the outcome will exceed this value.

Figure 2-3 and Figure 2-4 show the 2007 Reference Load Forecasts and the high and low uncertainty bands forecasts before DSM and including future rate level changes. The Reference forecasts and the uncertainty bands do not include uncertainty around DSM savings estimates. The probability assessments in Chapter 5 combine the load forecast distribution and the distribution around estimated DSM savings to create an estimate of and uncertainty bands around Net Demand (Demand less DSM savings).

**Figure 2-3 2007 Total Integrated Energy Requirements**

**Figure 2-4 2007 Total Integrated Peak Demand Requirements**
2.3 Existing and Committed Resources

This section provides the major differences between the 2006 IEP/LTAP and the 2008 LTAP with respect to BC Hydro’s existing and committed resources and the dependable capacity and firm energy capabilities reflected in the load/resource balances. These resources are reflected in the Load Resource Balances shown in this chapter and in Chapter 6 and the analysis contained in Chapter 5.

2.3.1 Heritage Hydro

The firm energy capability of the Heritage hydroelectric facilities is 42,600 GWh/year, which is consistent with Section 1(2) of SD 10 which provides that the definition of “firm energy capability” … “must be interpreted for the purposes of [SD 10] so as to be consistent with the fact that, in 2006, the authority’s firm energy capability was 42,600 gigawatt hours”.

The dependable capacity of the Heritage Hydro resources has been lowered by 55 MW to 9,707 MW because of over-gating restrictions on the existing Mica Units.

2.3.2 Heritage Thermal – Burrard Generating Station

Burrard is BC Hydro’s main natural gas-fired thermal generating facility. Following significant analysis and review since the 2006 IEP/LTAP, BC Hydro concludes that it must continue to rely on Burrard for its full capacity of 900 MW to reliably meet its obligations in the LM/VI region at least until 5L83 is in service including a potentially delayed 5L83 ISD. BC Hydro has also concluded that an appropriate maintenance program can be implemented to allow it to rely on the plant for 900 MW and 3,000 GWh/year for planning purposes through the planning horizon. The analysis and requests for Burrard are as follows:

• Analysis of social licensing risks, technical risks and options are shown in Section 5.4; and

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20 Over-gating is the practice of opening the wicket gates beyond the limit required to achieve the generator design output. Over-gating has been restricted on Mica Units 1 and 2 because of the undesirable operating conditions that results on these two units.
• The 2008 LTAP requests with respect to Burrard are set out in Section 6.2.3, including a request that the BCUC endorse BC Hydro’s plan to rely on Burrard for planning purposes for 900 MW and 3,000 GWh/year of firm energy.

2.3.3 Resource Smart Projects

Resource Smart projects at Aberfeldie and G.M. Shrum (GMS) Units 6-8 were included in the 2006 IEP/LTAP. Additional projects\(^\text{21}\) at Cheakamus, John Hart and GMS Units 1-5 are included in the supply stack for the 2008 LTAP.

2.3.4 Revelstoke Unit 5

The BCUC granted a Certificate of Public Convenience and Necessity (CPCN) to BC Hydro for Revelstoke Unit 5 on 12 July 2007.\(^\text{22}\) The unit has been included in the supply stack.

2.3.5 Existing (Pre-F2006) IPP Supply Contracts and Alcan EPA

BC Hydro currently has EPAs with 48 IPPs that were signed prior to F2006 with eight of the associated projects not yet having reached commercial operation.\(^\text{23}\) In F2012 (the first year of the planning horizon), BC Hydro forecasts it will procure about 6,200 GWh of firm energy with about 46 per cent of this amount from natural gas-fired projects, 40 per cent from small hydro, 13 per cent from biomass and 1 per cent from other resources. This represents about 400 GWh approximately 700 GWh less than in the 2006 IEP/LTAP.\(^\text{24}\)

BC Hydro has assumed that three existing biomass contracts will not be renewed upon EPA expiry (between F2014 and F2022) due to pricing and fuel supply risks. Together the expiry

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\(^{21}\) These additional projects, once online, contribute an additional 202 GWh /yr or 66 MW to the energy and capacity load resource balances relative to the 2006 IEP/LTAP.

\(^{22}\) BCUC Order No. C-8-07.

\(^{23}\) BC Hydro assumes these eight sites will contribute 400 GWh of energy or 50 MW of dependable capacity in F2012, including attrition, to the Load/Resource Balance. A higher attrition factor has been used for these sites (76 per cent attrition factor).

\(^{24}\) BC Hydro has used a FELCC assessment, initially conducted to determine physically firm energy volumes for small hydro contracts without firm contractual commitments in the SOP, including 85 per cent of contracted energy volumes from existing Pre-F2006 Call EPAs, which removes about 300 GWh/year of firm energy from the resource stack to determine that 85 per cent of contracted energy from existing small hydro IPPs should be included in the supply stack rather than 100 per cent as was the case in the 2006 IEP/LTAP. As such, approximately 400 GWh/year of firm energy from existing Pre-F2006 EPAs has been removed from the supply stack relative to the 2006 IEP/LTAP. See Appendix F12 for an explanation of the analysis.
of these three EPAs removes about 800 GWh/year of IPP supply by the end of the planning horizon. The renewal of all other existing IPP contracts is assumed, upon EPA expiry, for the remainder of the planning horizon. These renewal assumptions are consistent with BC Hydro’s approach in the last IEP/LTAP and recent regulatory filings for the Revelstoke Unit 5 CPCN, the Alcan Inc. (Alcan) 2007 EPA and the SOP.

On January 29, 2008 the BCUC accepted the Alcan 2007 EPA. Energy and capacity from the Alcan 2007 EPA are included in the supply stack, amounting to 900 GWh of firm energy and 200 MW of dependable capacity in F2012.

2.3.6 IPP Supply from F2006 Call

BC Hydro presently has commitments to purchase electricity from 35 IPPs that signed EPAs in the F2006 Call process. In F2012, BC Hydro forecasts it will obtain about 2,900 GWh of firm IPP energy from F2006 Call projects with about 55 per cent of this amount from small hydro, 27 per cent from biomass, 15 per cent from wind projects and 3 per cent from other. Included in this amount is about 400 GWh of firm energy from the small project stream of the F2006 Call. Additionally, another 200 GWh of firm energy will be provided by the Brilliant Expansion 2 project which was awarded an EPA in an acquisition process conducted parallel to the F2006 Call.

The load/resource balances reflect the termination of one of the two F2006 Call coal/biomass projects (i.e., AESWapiti). Capacity and energy associated with the second coal/biomass EPA have been removed from the supply stack because the current project configuration is not considered viable due to the zero GHG requirement contained in Policy Action No. 20 of the 2007 Energy Plan and the Emissions Standards Act (described in section 4.2). The two coal/biomass EPAs represented 1,400 GWh/year of energy, or

25 BCUC Order No. E-3-08.

26 See Appendix F12 for an explanation of the FELCC analysis to determine small hydro firm energy contribution from small hydro IPPs without firm contracted commitments.

27 BC Hydro has used an FELCC assessment, initially conducted to determine physically firm energy volumes for small hydro contracts without contractual commitments in the SOP, to determine that 85 per cent of contracted energy from small hydro IPPs, awarded EPA in the F2006 Call, small project stream, should be included in the supply stack rather than 0 per cent as was the case in the 2006 IEP/LTAP. As such,
28 per cent of total F2006 Call energy awarded after attrition. BC Hydro is assuming about a 30 per cent attrition factor for the remaining F2006 Call projects.

2.3.7 Attrition Rate for Past Calls

The rate of attrition for BC Hydro's previous electricity calls is summarized in Table 2-5.

<table>
<thead>
<tr>
<th>Call</th>
<th>Awarded GWh/year</th>
<th>Terminated GWh/year</th>
<th>Forecast Attrition GWh/year</th>
<th>Terminated + Forecast Attrition GWh/year</th>
<th>Combined Attrition Factor (per cent)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Pre-2000 EPAs</td>
<td>6,727</td>
<td>0</td>
<td>0</td>
<td>0</td>
<td>0</td>
</tr>
<tr>
<td>2000 Green RFEOI</td>
<td>153</td>
<td>0</td>
<td>0</td>
<td>0</td>
<td>0</td>
</tr>
<tr>
<td>2001 Green Energy Call</td>
<td>891</td>
<td>176</td>
<td>0</td>
<td>176</td>
<td>20</td>
</tr>
<tr>
<td>2002 CBG Call</td>
<td>342</td>
<td>0</td>
<td>62</td>
<td>62</td>
<td>18</td>
</tr>
<tr>
<td>2002/03 GPG Call</td>
<td>1,764</td>
<td>207</td>
<td>881</td>
<td>1,088</td>
<td>62</td>
</tr>
<tr>
<td>2003/04 VICFT</td>
<td>1,800</td>
<td>1,800</td>
<td>0</td>
<td>1,800</td>
<td>100</td>
</tr>
<tr>
<td>F2006 Call</td>
<td>7,093</td>
<td>1,677</td>
<td>1,630</td>
<td>3,307</td>
<td>47</td>
</tr>
<tr>
<td>Total</td>
<td>18,768</td>
<td>3,860</td>
<td>2,573</td>
<td>6,433</td>
<td>34</td>
</tr>
</tbody>
</table>

FREOI – Request for Express of Interest
CBG – Customer-Based Generation
CPG – Green Power Generation
VICFT – Vancouver Island Call for Tenders

2.3.8 SOP

The BCUC accepted BC Hydro's SOP Application on March 19, 2008 and the program was launched on April 11, 2008. Based on the assumed volumes included in the SOP Application, BC Hydro has included 330 GWh/year of energy and 30 MW of dependable capacity in the supply stack in F2012.

2.3.9 Capacity

A summary of the dependable capacity of existing resources is set out in Table 2-6.
Table 2-6 Dependable Capacity of BC Hydro’s existing resources at the start of the planning horizon (F2012)

<table>
<thead>
<tr>
<th>Component</th>
<th>Dependable Capacity 2008 LTAP (MW)</th>
<th>Dependable Capacity 2006 IEP/LTAP (MW)</th>
<th>Source or Description regarding Differences from 2006 IEP/LTAP</th>
</tr>
</thead>
<tbody>
<tr>
<td>Heritage Hydroelectric</td>
<td>9,700</td>
<td>9,800</td>
<td>Mica dependable capacity reduced because of over-gating restriction.</td>
</tr>
<tr>
<td>Heritage Thermal</td>
<td>950</td>
<td>950</td>
<td>No significant differences.</td>
</tr>
<tr>
<td>Resource Smart</td>
<td>50</td>
<td>100</td>
<td>Additional capacity projects at GMS (Units 1 to 5). Some ISDs have changed.</td>
</tr>
<tr>
<td>Revelstoke Unit 5</td>
<td>500</td>
<td>0</td>
<td>Included as a committed resource.</td>
</tr>
<tr>
<td>Existing IPPs</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Clean or Renewable</td>
<td>300</td>
<td>300</td>
<td>No significant differences.</td>
</tr>
<tr>
<td>Other</td>
<td>350</td>
<td>350</td>
<td>No significant differences.</td>
</tr>
<tr>
<td>F2006 Call</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Clean or Renewable</td>
<td>250</td>
<td>300</td>
<td>2008 LTAP assumes a lower capacity contribution from small hydro resources based on updated ELCC and Loss of Load Expectation analysis.</td>
</tr>
<tr>
<td>Other</td>
<td>0</td>
<td>200</td>
<td>Both F2006 Call coal/biomass projects have been removed from the supply stack.</td>
</tr>
<tr>
<td>Alcan 2007 EPA</td>
<td>200</td>
<td>0</td>
<td>New contract with Alcan.</td>
</tr>
<tr>
<td>SOP</td>
<td>50</td>
<td>0</td>
<td>New program.</td>
</tr>
<tr>
<td>Total Dependable Capacity in F2012</td>
<td>12,350</td>
<td>12,000</td>
<td></td>
</tr>
</tbody>
</table>

1. 2.3.10 Energy

BC Hydro determines its ability to meet its customers’ energy requirements using a FELCC calculation. The FELCC is defined as the maximum amount of annual energy that a hydroelectric system can produce under critical water conditions where critical water conditions are the most adverse sequence of stream flows occurring within the historical record.  

29 BC Hydro has previously discussed FELCC in the 2006 IEP/LTAP Application, page 2-24; the 2007 Alcan EPA Report, pages 4-11 and 4-12; and the SOP Application, pages 3-4 to 3-8.
in Table 2-7. Details behind the FELCC of the existing resources are contained in Appendix F12.

<table>
<thead>
<tr>
<th></th>
<th></th>
<th></th>
<th></th>
</tr>
</thead>
<tbody>
<tr>
<td>Heritage Hydroelectric</td>
<td>42,600</td>
<td>42,600</td>
<td>No differences. SD 10 establishes the “firm energy capability” to be 42,600 GWh/year.</td>
</tr>
<tr>
<td>Heritage Thermal</td>
<td>3,200</td>
<td>6,300</td>
<td>As further described above, BC Hydro has established Burrard’s energy contribution for planning purposes as 3,000 GWh/yr.</td>
</tr>
<tr>
<td>Resource Smart</td>
<td>300</td>
<td>300</td>
<td>Additional projects included at John Hart, Cheakamus and GMS.</td>
</tr>
<tr>
<td>Revelstoke Unit 5</td>
<td>130</td>
<td>N/A</td>
<td>Based on Revelstoke Unit 5 CPCN Application.</td>
</tr>
</tbody>
</table>

### Existing IPPs

| Clean or Renewable 30   | 3,400                                | 4,1004,200                         | Firm energy from existing small hydro IPPs has been reduced such that 85 per cent of contracted annual energy is included as firm energy in the 2008 LTAP compared to 100 per cent in the 2006 IEP/LTAP. |
| Other 31               | 2,800                                | 2,8002,700                         | No significant differences. |

| F2006 Call Clean or Renewable | 3,100                        | 2,800                        | Firm energy from hydro IPPs in the F2006 CFT small project stream has been increased with 85 per cent of contracted annual energy from these projects included as firm energy in the 2008 LTAP compared to zero per cent in the 2006 IEP/LTAP. |
| Other                    | 0                              | 1,400                        | Two coal/biomass projects have been removed from the supply stack. |

| Alcan 2007 EPA           | 900                            | N/A                          | New contract with Alcan |
| SOP                      | 300                            | 0                            | New program |
| Total FELCC in F2012     | 56,700                        | 60,300                       |

30 Consisting of 48 EPAs as follows: (a) Pre-2000 EPAs (including Arrow Lakes Hydro and NWE Williams Lake); (b) 2000 Green RFEOI; (c) 2001 Green Energy Call; (d) 2002 Customer-Based Generation Call; and (e) 2002/2003 Green Power Generation Call.

31 Consisting of Island Cogeneration Plant and McMahon Cogeneration Plant.

BC Hydro 2008 Long Term Acquisition Plan

[Revision 3 – September 5, 2008]
2.3.11 SD 10 Impact on Resource Requirements

Section 3 of SD 10 provides that the BCUC must use the criterion that BC Hydro is to achieve energy and capacity self-sufficiency by becoming capable of meeting, by 2016 and each year thereafter, its mid energy and peak forecasts "solely from electricity generating facilities within the Province, assuming no more in each year than the firm energy capability from the assets that are hydroelectric facilities". The phrase "firm energy capability" as defined in subsection 1(1) of SD 10 to mean “the maximum amount of annual energy that a hydroelectric system can produce under critical water conditions". The term "critical water conditions" is defined in subsection 1(1) to mean “the most adverse sequence of stream flows occurring within the historical record”. Finally, section 1(2) of SD 10 provides that the definition of “firm energy capability” … “must be interpreted for the purposes of [SD 10] so as to be consistent with the fact that, in 2006, the authority’s firm energy capability was 42,600 gigawatt hours”. As a result:

- The Canadian Entitlement (CE) is the Canadian portion of the additional electricity produced in the Columbia River in the western U.S. as a result of provisions of the Columbia River Treaty of 1961 and has not been included in the 2008 LTAP load/resource balances other than as a contingency resource because it is not generated "solely from electricity facilities within the Province". This is consistent with the BCUC’s Decision on Revelstoke Unit 5 where the BCUC agreed that"…the Canadian Entitlement is not a suitable source of dependable capacity in the long-term." The CE continues to be a contingency resource option.

- The 2,500 GWh/year non-firm/market allowance has been removed from the 2008 LTAP energy load/resource balances after 2015. The 2,500 non-firm/market allowance consists of three components: (1) Heritage hydro non-firm energy, (2) imported non-firm energy and (3) domestic IPP non-firm energy. SD 10 precludes reliance on Heritage hydro non-firm energy. SD 10 also provides that external markets cannot be relied upon after 2015 for purposes of meeting BC Hydro’s mid-level energy and peak forecasts. The third component - domestic IPP non-firm energy - has been included in the load/resource balance pursuant to FELCC studies as described above and in Appendix F12.

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32 In the Matter of British Columbia Hydro and Power Authority’s Application for a Certificate of Public Convenience and Necessity for Revelstoke Unit 5, Decision, July 12, 2007, page 65.
• The 400 MW market reliance for has been removed from the capacity load/resource balances after 2015, as the 400 MW relies on external markets and is not a domestic resource. Reliance on the estimated market for capacity in the 2008 LTAP is reflected in the contingency resource reliance on the CE.

2.4 The Load/Resource Balance

The purpose of the load/resource balance is to compare the annual obligations for the twenty year study period of the 2008 LTAP with the annual capability of BC Hydro’s resources. This is done with respect to two views of the system, the energy balance and the capacity balance.

• Based on the 2007 Load Forecast and existing and committed resources, the energy balance shows resource deficits of 3,000 GWh in F2012, 14,000 GWh in F2020 and 21,700 GWh in F2028. Refer to Figure 2-5. Chapter 6 describes BC Hydro’s plan to acquire sufficient energy resources to eliminate these deficits.
The capacity load resource balance compares the existing and committed generating capability to the 2007 Load Forecast system peak load including reserve requirements. The capacity balance shows resource deficits of 200 MW in F2012, 1,700 MW in F2020 and 3,000 MW in F2028. Refer to Figure 2-6. Chapter 6 describes BC Hydro’s plan to acquire sufficient capacity resources to eliminate these deficits.

**Figure 2-6 Capacity Load / Resource Balance**

### 2.5 Regional Issues and Constraints

This section presents load/resource balances for the two regions that are material to the 2008 LTAP analysis: (1) the Fort Nelson area; (2) the LM/VI region.

#### 2.5.1 Fort Nelson

The Fort Nelson area is located within BC Hydro’s service area in northeast B.C., but is electrically integrated with the Alberta electricity system. The load in the Fort Nelson area is normally met from BC Hydro’s FNG. BC Hydro relies on the interconnection to Alberta to

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33 Representation of generation, reserves and load in the load resource balance has been described in Appendix F10. Appendix F18 is reproduced from BC Hydro’s 2007 Alcan EPA Report Appendix I. Also refer to BC Hydro’s response in Appendix C to the BCUC’s 2006 IEP/LTAP Directive 8.
provide backup to FNG. Reliable supply in the Fort Nelson region is generally a capacity related issue, given that its supply is provided by thermal generation backed up by imports.

The load in the region has grown to the point that new resources are required to be able to reliably meet the demand. Given the activity in the area, BC Hydro has identified in Figure 2-7 three scenarios of future load growth in addition to the Reference Forecast for the region.

Figure 2-7 Fort Nelson Region Peak Demand Reference Forecast and Scenarios

Reliability analysis for Fort Nelson region is based on the N-1 reliability criterion. Under this planning criterion, the load must be able to be served when the largest single supply source “N” is out of service. The Load/Resource balance for Fort Nelson in Figure 2-8 presents all supply resources in the supply stack and adds the largest single supply to the load such that the gap shown in Figure 2-8 is the gap as measured by the N-1 criterion.

There is a possibility of a significant increase in industrial demand in the region which, absent new supply resources, BC Hydro will not be able to serve. Recent load additions in the region have stretched the system to the point that there are times when firm loads must
be served on a curtailable basis. This is reflected in Figure 2-8 where there is a 
load/resource gap in 2008 and in every succeeding year under every load scenario.

A specific resource plan for the Fort Nelson area is contained in Appendix N1. The resource 
plan considers BC Hydro’s requirements to meet the Reference Forecast identified in Figure 
2-7 as well as various scenarios of additional load growth.

2.5.2 Lower Mainland/Vancouver Island

The LM/VI region is the principal load centre for the BC Hydro system accounting for 
73 per cent of total system peak load while containing only 23 per cent of system 
dependable capacity. The LM/VI region depends on the ILM network for the majority of its 
capacity supplies to be delivered from interior generating plants located primarily on the 
Peace and Columbia rivers. Currently, the ILM network has a system normal rating of 
5800 MW, but under single contingency or “N-1” conditions the rating is only 5000 MW.
Based on the “N-1” rating for ILM, the total dependable supply available to the LM/VI region in F2012 will be approximately 7700 MW. By comparison, the peak load in the LM/VI region in F2012 will be just over 8200 MW assuming the mid forecast, which indicates a capacity shortfall of approximately 500 MW (not accounting for incremental DSM, supply side resources or regional reserve requirements). Refer to Figure 2-9. The corresponding capacity shortfall in F2012 for the integrated system as a whole (i.e., under the same assumptions of mid load, no new DSM or supply side resources) will be about 200 MW (as shown in Figure 2-6). Therefore, until the ILM network is reinforced, the LM/VI region will be more capacity critical than the rest of the system (e.g., by approximately 300 MW in F2012). Further, as shown in Figure 2-10, once the ILM network is reinforced, the system capacity requirements will likely revert to being driven by overall system needs, as opposed to the regional needs for LM/VI.

BCTC has identified a second Nicola to Meridian 500 kV transmission line, circuit 5L83, as the preferred ILM reinforcement option and the CPCN process for this line is currently underway. With 5L83 in-service, the “N-1” rating of the ILM network would increase by 1750 MW (i.e., from 5000 MW to 6750 MW). The ILM CPCN proceeding is expected to be completed by July 3, 2008. BC Hydro is working with BCTC to develop operational contingency plans should the project be delayed beyond the present expected ISD of October 2014. Interim ILM reinforcement measures are also being considered to meet reliability standards. Section 6.4.3 provides an analysis of the implications of a delay in getting 5L83 into service.
Figure 2-9  Load/Resource Balance for the LM/VI
Without 5L83 ILM upgrade

Figure 2-10  Load/Resource Balance for the LM/VI With 5L83 ILM upgrade
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Chapter

3

RESOURCE OPTIONS
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3.1 Introduction

Step 3 (see Figure 1-1) in this 2008 LTAP is to provide background information on the various resources considered for meeting future capacity and energy needs. Organized by major category, these resources consist of DSM (section 3.2), supply-side generation (section 3.3) and transmission resource options (section 3.4). The chapter concludes with a discussion in section 3.5 of the financial assumptions underpinning the ROU.

BC Hydro undertook a targeted ROU of the supply-side resource options. Only resource options impacted by Government policy and regulatory initiatives or whose availability or costs have materially changed since the 2006 IEP/LTAP, and which materially impact the portfolio analysis, have been updated. For each supply-side resource there is a summary of the scope of changes undertaken for the analysis and a description of the methodology applied to update the data and the findings. First Nations and stakeholder engagement with respect to resource options can be found in Appendix Q.

3.2 Demand Side Management

This section describes the DSM-related resource options used for portfolio analysis. The DSM Plan itself, together with the cost-effectiveness analysis of the DSM Plan components, are described in section 5.5, 6.2.1 and Appendix K.

Section 1 of the UCA defines “demand side measures” to mean “a rate, action or program undertaken (a) to increase energy or promote energy efficiency, (b) to reduce the energy demand a public utility must serve, or (c) to shift the use of energy to periods of lower demands.” Section 44.4(c) 44.1(4)(c) contemplates that BC Hydro’s long-term resource plans will include “demand-side measures taken by the Government of British Columbia or of Canada or a local authority”. Based on this definition, BC Hydro’s DSM options included codes and standards and rate structures undertaken for the purpose set out in (a) and (b), but did not include general rate increases which are a load forecasting issue.

BC Hydro developed two DSM options for consideration in this LTAP: a smaller option (DSM Option A) that would save a planned 10,800 GWh per year in F2020 and a larger
option (DSM Option B) that would save a planned 13,000 GWh per year in F2020. Both
options included the same components, including codes and standards, rate structures and
DSM programs and a series of supporting initiatives. Figure 3-1 summarizes the contents of
the DSM options.

The contents of the two options, and the differences between them, are summarized below.

3.2.1 DSM Option Components

3.2.1.1 Codes and Standards

The smaller option, Option A, includes changes to energy efficiency regulations that have
been enacted or announced or are planned by the Federal and B.C. Governments, while
Option B also includes changes that are possible in BC Hydro’s opinion but not yet planned
by either Government. Table 3-1 lists the codes and standards included in Options A and B,
together with the level of Government responsible. Further information on these codes and
standards is provided in Appendix F17. Additional information on Option A codes and
standards is provided in the DSM Plan attached as Appendix K, Sub-Appendix D.
### Table 3-1 Option A: Codes and Standards in DSM Options A & B

<table>
<thead>
<tr>
<th>Category</th>
<th>Options A and B</th>
<th>Additional Items in Option B</th>
</tr>
</thead>
<tbody>
<tr>
<td>Electronic equipment</td>
<td>Standby power, set-top boxes, external power supplies, battery chargers (all Federal Government)</td>
<td></td>
</tr>
<tr>
<td>Incandescent lighting</td>
<td>Federal Government</td>
<td></td>
</tr>
<tr>
<td>Other residential equipment</td>
<td>Ceiling fans (Federal Government), furnace blower motors (B.C. Government), torchieres (Federal Government), hot tubs (Federal Government), room air-conditioners (B.C. Government)</td>
<td>Seasonal lights (B.C. or Federal Government), drinking water coolers (B.C. Government)</td>
</tr>
<tr>
<td>Building code</td>
<td>B.C. Government</td>
<td>B.C. Government</td>
</tr>
<tr>
<td>Appliances</td>
<td>Clothes washers (B.C. Government), refrigerators and freezers (B.C. Government), dishwashers (Federal Government)</td>
<td></td>
</tr>
<tr>
<td>Large motors</td>
<td>B.C. Government</td>
<td></td>
</tr>
<tr>
<td>Commercial equipment</td>
<td>Streetlights (B.C. Government), high intensity discharge lamps and ballasts (Federal Government), packaged terminal air-conditioners (Federal Government), ice-cube makers (Federal Government), large air-conditioners (Federal Government), commercial clothes washers (Federal Government)</td>
<td>Dusk to dawn luminaires and commercial building operators (B.C. Government)</td>
</tr>
</tbody>
</table>

1. Additional codes and standards opportunities may be possible over the plan period but BC Hydro did not include them in Option B because they are too uncertain for the purpose of resource planning at this time.

4. **3.2.1.2 Rate Structures**

5. The DSM options include two-step inclining block rate structures for the major rate classes as planned or indicative conservation rate structures. A hypothetical two-step inclining block rate structure is illustrated in Figure 3-2. The first block of electricity consumed during the billing period is priced at a lower price per kWh. Electricity consumed above the consumption threshold is priced at a higher price per kWh.
Two-step inclining block rate structures were modelled for the rate classes listed in Table 3-2 for the purpose of the DSM Plan and LTAP. Further information on these rate structures is provided in Appendix F17 and in the DSM Plan attached as Appendix K, Sub-Appendix E.

<table>
<thead>
<tr>
<th>Sector</th>
<th>Rate Class</th>
</tr>
</thead>
<tbody>
<tr>
<td>Residential</td>
<td>Residential (application filed February 2008)</td>
</tr>
<tr>
<td>Commercial</td>
<td>Small general service (&lt; 35 kW)</td>
</tr>
<tr>
<td></td>
<td>Large general service (&gt; 35 kW)</td>
</tr>
<tr>
<td>Industrial</td>
<td>Large general service (&gt; 35 kW)</td>
</tr>
<tr>
<td></td>
<td>Transmission (existing)</td>
</tr>
</tbody>
</table>

The differences between Option A and Option B are that Option B includes different rate structures that would produce more electricity savings by delivering a higher Tier 2 price signal to consumers or exposing more customer load to the Tier 2 price signal. Typically, they involve a larger Tier 1 block and a smaller Tier 2 block, relative to an Option A rate structure, to deliver a higher Tier 2 price while maintaining class revenue neutrality.
The rate structures included in Options A and B reflect consideration of the balance between energy conservation and customer bill impacts. Rate structures more aggressive than those in Option B were not selected because they would have resulted in unacceptable bill impacts.

3.2.1.3 Programs

Both Option A and Option B included the same DSM programs listed in Table 3-3 below. However, for Option B, the programs included higher incentive levels and marketing efforts to drive additional customer participation. Further information on these programs is provided in Appendix F17 and in the DSM Plan attached as Appendix K, Sub-Appendix F.

<table>
<thead>
<tr>
<th></th>
<th>Residential</th>
<th>Commercial</th>
<th>Industrial</th>
</tr>
</thead>
<tbody>
<tr>
<td>Behaviour</td>
<td>Power Smart Partner</td>
<td>Mechanical Pulping</td>
<td></td>
</tr>
<tr>
<td>Voltage Optimization</td>
<td>Product Incentive</td>
<td>Power Smart Partner – Transmission</td>
<td></td>
</tr>
<tr>
<td>Lighting</td>
<td>High Performance Building</td>
<td>Power Smart Partner – Distribution</td>
<td></td>
</tr>
<tr>
<td>Sustainable Community</td>
<td>Voltage Optimization</td>
<td>New Plant Design</td>
<td></td>
</tr>
<tr>
<td>Refrigerator Buy-Back</td>
<td>Sustainable Community</td>
<td>Load Displacement</td>
<td></td>
</tr>
<tr>
<td>Renovation Rebate</td>
<td>Load Displacement</td>
<td>Sector Enabling Activities</td>
<td></td>
</tr>
<tr>
<td>New Home</td>
<td>Sector Enabling Activities</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Low Income</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Appliances and Electronics</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Load Displacement</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Sector Enabling Activities</td>
<td></td>
<td></td>
<td></td>
</tr>
</tbody>
</table>

Programs in Option A were designed to increase electricity savings from programs in the F2008-F2020 period over historic levels. Programs in Option B were designed to further
increase participation levels using higher incentive levels and marketing efforts. While additional savings may be possible, BC Hydro did not include them because they are too uncertain for the purpose of resource planning at this time.

3.2.1.4 Supporting Initiatives

Both Options A and B included the same six supporting initiatives:

- Public Awareness and Education;
- Codes and Standards Support;
- Community Engagement;
- Technology Innovation;
- Indirect and Portfolio Enabling; and
- Information Technology.

3.2.2 Summary of DSM Option A and Option B

BC Hydro considered the two DSM options to be reasonable for resource planning purposes because they: a) align with the UCA and the 2007 Energy Plan, b) employ a comprehensive mix of DSM tools and c) are based on the best available information from BC Hydro’s 2007 CPR and other research.

Table 3-4 presents the two options’ electricity savings in F2020, the milestone year for the 2007 Energy Plan’s conservation target, along with their cost. For Tables 3-4 through 3-8, DSM savings are at the customer meter, and do not include the savings attributable to distribution or transmission losses.
Table 3-4  DSM Electricity Savings and Costs\textsuperscript{34}

<table>
<thead>
<tr>
<th>Option</th>
<th>Planned Energy Savings in F2020 (GWh/year)</th>
<th>Planned Capacity Savings in F2020 (MW)</th>
<th>All Ratepayers (Total Resource) Levelized Cost ($/MWh)\textsuperscript{35}</th>
</tr>
</thead>
<tbody>
<tr>
<td>A</td>
<td>10,820</td>
<td>1,730</td>
<td>41</td>
</tr>
<tr>
<td>B</td>
<td>13,030</td>
<td>2,100</td>
<td>42</td>
</tr>
</tbody>
</table>

The development of Option A involved independent decisions on the components within each of codes and standards, rate structures and programs. When integrated into a combined option, they resulted in planned energy savings in F2020 of 10,820 GWh per year. Since this approximated the 10,000 GWh by 2020 figure noted in the 2007 Energy Plan, BC Hydro left it as is for the purpose of portfolio analysis. Option B comprises additional or different actions and tactics to achieve incremental electricity savings. While additional savings beyond Option B may be feasible, BC Hydro did not include them because they are too uncertain for the purpose of resource planning at this time.

BC Hydro did not analyze a smaller option than Option A because of the 10,000 GWh by 2020 figure in Policy Action No. 1 of the 2007 Energy Plan, which BC Hydro interpreted as a call for DSM savings of at least that amount, and 2007 Energy Plan Policy Action No. 3, which called on utilities “to pursue all cost-effective investments in demand side management”\textsuperscript{36}. Policy Action No. 3 has now been given the force of law pursuant to subsection 44.1(2)(b), which provides that public utilities must file a long-term plan that shows how the public utility intends to reduce demand by taking cost-effective demand-side

\textsuperscript{34} These DSM savings figures are one of three sets in this LTAP. These planned savings are the first set and represent the starting point. They were inputs to the probability assessment discussed in Chapter 5 which produced a second set of figures, comprising high, mid and low DSM outcomes with associated probabilities, which were inputs to the portfolio analysis discussed in Chapter 5. A third set for Option A resulted from updates and refinements that were carried out after it was submitted for the portfolio analysis so that the DSM expenditure request would be based on the best available information. The differences between each set are small and not material for portfolio analysis.

\textsuperscript{35} These values are based on the results of the portfolio analysis in Chapter 5 and include the effects of the transmission and distribution loss savings. The All Ratepayers levelized cost in F2008 dollars is similar for Options A and B because the higher unit cost of incremental DSM savings is offset by spreading fixed program and portfolio-level costs over a larger volume of savings. The All Ratepayers cost of the incremental 2,200 GWh/yr achieved by Option B is $50/MWh.

measures. As such, Options A and B were used in the 2008 LTAP portfolio analysis because they represent feasible DSM options within the constraints established by government policy and resource planning requirements.

Table 3-5, Table 3-6, Table 3-7 and Table 3-8 provide a breakdown of each option's planned energy and capacity savings by sector and DSM tool.

### Table 3-5  Option A: Planned Energy Savings

<table>
<thead>
<tr>
<th>Codes and Standards</th>
<th>Rate Structures</th>
<th>Programs</th>
<th>Total</th>
</tr>
</thead>
<tbody>
<tr>
<td>Residential</td>
<td>2,640</td>
<td>800</td>
<td>1,230</td>
</tr>
<tr>
<td>Commercial</td>
<td>540</td>
<td>370</td>
<td>1,490</td>
</tr>
<tr>
<td>Industrial</td>
<td>110</td>
<td>800</td>
<td>2,840</td>
</tr>
<tr>
<td>Total *</td>
<td>3,290</td>
<td>1,970</td>
<td>5,560</td>
</tr>
</tbody>
</table>

*Totals may not add due to rounding.

### Table 3-6  Option A: Planned Capacity Savings

<table>
<thead>
<tr>
<th>Codes and Standards</th>
<th>Rate Structures</th>
<th>Programs</th>
<th>Total</th>
</tr>
</thead>
<tbody>
<tr>
<td>Residential</td>
<td>550</td>
<td>100</td>
<td>300</td>
</tr>
<tr>
<td>Commercial</td>
<td>70</td>
<td>60</td>
<td>200</td>
</tr>
<tr>
<td>Industrial</td>
<td>10</td>
<td>100</td>
<td>330</td>
</tr>
<tr>
<td>Total *</td>
<td>640</td>
<td>270</td>
<td>830</td>
</tr>
</tbody>
</table>

* Totals may not add due to rounding.

### Table 3-7  Option B: Planned Energy Savings

<table>
<thead>
<tr>
<th>Codes and Standards</th>
<th>Rate Structures</th>
<th>Programs</th>
<th>Total</th>
</tr>
</thead>
<tbody>
<tr>
<td>Residential</td>
<td>2,700</td>
<td>1,060</td>
<td>1,430</td>
</tr>
<tr>
<td>Commercial</td>
<td>700</td>
<td>470</td>
<td>1,770</td>
</tr>
<tr>
<td>Industrial</td>
<td>110</td>
<td>840</td>
<td>3,960</td>
</tr>
<tr>
<td>Total *</td>
<td>3,500</td>
<td>2,370</td>
<td>7,160</td>
</tr>
</tbody>
</table>

* Totals may not add due to rounding.
Table 3-8  Option B: Planned Capacity Savings

<table>
<thead>
<tr>
<th></th>
<th>Codes and Standards</th>
<th>Rate Structures</th>
<th>Programs</th>
<th>Total</th>
</tr>
</thead>
<tbody>
<tr>
<td>Residential</td>
<td>560</td>
<td>190</td>
<td>360</td>
<td>1,120</td>
</tr>
<tr>
<td>Commercial</td>
<td>90</td>
<td>70</td>
<td>240</td>
<td>410</td>
</tr>
<tr>
<td>Industrial</td>
<td>10</td>
<td>110</td>
<td>460</td>
<td>580</td>
</tr>
<tr>
<td>Total *</td>
<td>670</td>
<td>380</td>
<td>1,060</td>
<td>2,100</td>
</tr>
</tbody>
</table>

*Totals may not add due to rounding.

Figures 3-3 and 3-4 show the DSM energy and capacity savings included in the 2006 IEP/LTAP and the 2008 LTAP. The 2006 IEP/LTAP DSM values were reduced to account for actual DSM savings in F2006 as the 2008 LTAP DSM values are based in F2007.

Figure 3-3  DSM Energy Savings in the 2006 LTAP and 2008 LTAP Option A and B
3.3 Supply-Side Options

3.3.1 Supply-Side ROU Scope

The supply-side resource options considered in the 2008 LTAP include the following characteristics:

- Considered “feasible” as defined in Guideline 3 of the BCUC’s Resource Planning Guidelines. Guideline 3 provides that “feasible resource options are defined as those options consistent with the objectives of the resource planning process, as established under Guideline No. 1. For example, government policy may rule out a particular technology or form of energy”. All supply-side options are consistent with B.C. Government policy and related legislative initiatives, which means among other things that only supply-side options located in B.C. are examined;

• Consistent with BCUC Directives; and

• Greater than 50 kW.

The ROU examines the following aspects of supply side options:

• Technical characteristics, including potential availability of the resource and characteristics of the technology;

• Financial information including direct costs, levelized UEC, levelized unit capacity costs (UCC), project lead times and project life. Financial cost assessments of resources are provided in F2008 constant dollars with corresponding real discount rates and real cost of capital rates; and

• Social and environmental information. While GHG information was updated as described in section 4.2, other social and environmental attributes were updated in the ROU process only if readily available.

The specific supply options that were updated are:

• Small hydro, to reflect the resource potential subsequent to the F2006 Call and cost increases;

• Biomass, to reflect updates in resource potential and costs, and the B.C. Government’s Bioenergy Strategy38 and Policy Action No. 31 of the 2007 Energy Plan, which together direct BC Hydro to pursue biomass projects in a two phase Call;

• Wind, to reflect the potential subsequent to the F2006 Call and cost increases;

• Geothermal, to reflect cost increases;

• Coal, to assess the feasibility of coal-fired generation with CCS technology, as mandated by Policy Action No. 20 of the 2007 Energy Plan;

• Large hydro, to incorporate the most up to date cost information concerning Mica Unit 5, Mica Unit 6, Revelstoke Unit 6 and Site C; and to address Directive No. 21 of the

38 Released January 31, 2008; http://www.energyplan.gov.bc.ca/bioenergy.
2006 IEP/LTAP Decision to include both pumped storage on the Jordan River and WAX in the next ROU. The large hydro assessment also addresses intervenor requests for information concerning other potential large hydro resource options.

- Natural gas, to reflect current natural gas prices, technological developments and cost increases; and


Table 3-9 provides a high level summary of the components of the supply-side resource options updated for the 2008 LTAP.

Table 3-9 Summary of Resource Options Update Scope for the 2008 LTAP

<table>
<thead>
<tr>
<th>Resource Option</th>
<th>Technical</th>
<th>Financial</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>Potential Availability</td>
<td>Technology Characteristics</td>
</tr>
<tr>
<td>Small hydro</td>
<td>♦</td>
<td></td>
</tr>
<tr>
<td>Biomass</td>
<td>♦</td>
<td></td>
</tr>
<tr>
<td>Wind</td>
<td>♦</td>
<td></td>
</tr>
<tr>
<td>Geothermal</td>
<td>♦</td>
<td></td>
</tr>
<tr>
<td>Coal</td>
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<td>♦</td>
</tr>
<tr>
<td>Large hydro</td>
<td>♦</td>
<td></td>
</tr>
<tr>
<td>Natural gas</td>
<td>♦</td>
<td></td>
</tr>
</tbody>
</table>

Detailed assessments of all resource options are presented in Appendix F1.

3.3.2 Small Hydro

3.3.2.1 Methodology

Kerr Wood undertook a study, entitled “Run-of-River Hydroelectric Resource Assessment for British Columbia” (November 2007), using a geographic information system-based tool to assess the energy and capacity potential of every watershed in the province and performed a high level cost assessment of developing a run-of-river generating station at the sites which the tool indicated to be feasible for development (Appendix F5). The following criteria were used as a first screen of the potential sites to indicate if they were feasible for development:
• Mean Annual Flow: 0.1 - 200 m³/s;

• Static Head: 30 - 1,000 m;

• In-stream Power: > 500 kW; and

• Potential sites were excluded if they fell within a provincial or national park, were on known salmon bearing streams or were within 10 km of existing power generation projects or approved works under construction. See the above referenced report for further details.

3.3.2.2 Results

The small hydro resource option update identified over 8,000 potential projects. The UECs are approximately 25 – 50 per cent higher than the 2005 Resource Options Report (ROR), primarily due to construction cost inflation and materials cost inflation. These potential projects were prioritized by UEC and those projects that ranked below $110/MWh were included in the 2008 LTAP portfolio development process. This price threshold provided sufficient energy for 2008 LTAP purposes and included 197 potential projects with a combined annual energy of 8,416 GWh and an installed capacity of 1,982 MW. This information is contained in Table 3-10 and Table 3-11 and Figure 3-5.

<table>
<thead>
<tr>
<th>Price Bundle</th>
<th>Number of Projects</th>
<th>Potential Capacity (MW)</th>
<th>Annual Energy (GWh/yr)</th>
<th>Dependable Capacity (MW)</th>
<th>Firm Energy (GWh/yr)</th>
<th>Weighted Average UEC @ 6% Discount Rate ($/MWh)</th>
<th>Weighted Average UEC @ 8% Discount Rate ($/MWh)</th>
</tr>
</thead>
<tbody>
<tr>
<td>50 - 59</td>
<td>1</td>
<td>32</td>
<td>168</td>
<td>7</td>
<td>111</td>
<td>54</td>
<td>63</td>
</tr>
<tr>
<td>60 - 69</td>
<td>7</td>
<td>87</td>
<td>458</td>
<td>14</td>
<td>335</td>
<td>65</td>
<td>76</td>
</tr>
<tr>
<td>70 - 79</td>
<td>21</td>
<td>276</td>
<td>1,283</td>
<td>20</td>
<td>1,016</td>
<td>75</td>
<td>88</td>
</tr>
<tr>
<td>80 - 89</td>
<td>34</td>
<td>583</td>
<td>2,499</td>
<td>10</td>
<td>2,065</td>
<td>84</td>
<td>99</td>
</tr>
<tr>
<td>90 - 99</td>
<td>58</td>
<td>411</td>
<td>1,705</td>
<td>9</td>
<td>1,399</td>
<td>95</td>
<td>112</td>
</tr>
<tr>
<td>100 - 109</td>
<td>76</td>
<td>594</td>
<td>2,303</td>
<td>8</td>
<td>1,866</td>
<td>105</td>
<td>123</td>
</tr>
<tr>
<td>TOTAL</td>
<td>197</td>
<td>1,982</td>
<td>8,416</td>
<td>68</td>
<td>6,791</td>
<td>-</td>
<td>-</td>
</tr>
</tbody>
</table>
Table 3-11  Small Hydro Project Summary by Region

<table>
<thead>
<tr>
<th>Transmission Region</th>
<th>Number of Projects</th>
<th>Potential Capacity (MW)</th>
<th>Annual Energy (GWh/yr)</th>
<th>Dependable Capacity (MW)</th>
<th>Firm Energy (GWh/yr)</th>
</tr>
</thead>
<tbody>
<tr>
<td>VANCOUVER ISLAND</td>
<td>8</td>
<td>44</td>
<td>155</td>
<td>3</td>
<td>125</td>
</tr>
<tr>
<td>SOUTH INTERIOR</td>
<td>16</td>
<td>142</td>
<td>495</td>
<td>0</td>
<td>385</td>
</tr>
<tr>
<td>PEACE RIVER</td>
<td>3</td>
<td>70</td>
<td>252</td>
<td>0</td>
<td>228</td>
</tr>
<tr>
<td>NORTH COAST</td>
<td>26</td>
<td>293</td>
<td>1,273</td>
<td>0</td>
<td>1,041</td>
</tr>
<tr>
<td>LOWER MAINLAND</td>
<td>88</td>
<td>819</td>
<td>3,909</td>
<td>63</td>
<td>2,988</td>
</tr>
<tr>
<td>KELLY</td>
<td>10</td>
<td>101</td>
<td>397</td>
<td>1</td>
<td>330</td>
</tr>
<tr>
<td>NICOLA</td>
<td>18</td>
<td>174</td>
<td>660</td>
<td>0</td>
<td>579</td>
</tr>
<tr>
<td>EAST KOOTENAY</td>
<td>19</td>
<td>244</td>
<td>900</td>
<td>2</td>
<td>764</td>
</tr>
<tr>
<td>CENTRAL INTERIOR</td>
<td>9</td>
<td>94</td>
<td>374</td>
<td>0</td>
<td>350</td>
</tr>
<tr>
<td><strong>TOTAL</strong></td>
<td><strong>197</strong></td>
<td><strong>1,982</strong></td>
<td><strong>8,416</strong></td>
<td><strong>68</strong></td>
<td><strong>6,791</strong></td>
</tr>
</tbody>
</table>

Figure 3-5  2008 LTAP ROU Supply Curves
Small Hydro UEC (Adjusted*)

* 2008 costs including estimates for Cost of Incremental Firm Transmission (CIFT), line losses and a capacity credit.
3.3.3 Biomass

Biomass is an energy resource fuelled by the combustion of organic materials.

3.3.3.1 Methodology

BC Hydro focused its updates on cost and potential availability of woodwaste, municipal solid waste (MSW) and biogas generated from municipal landfills. The ROU evaluates the technical and financial characteristics of options with the same methodology used by BC Hydro in its 2006 IEP/LTAP. The methodology for updating biomass varied depending on the type of biomass being reviewed, as described below.

Woodwaste: BC Hydro looked at three sources of woodwaste: sawmill woodwaste, roadside woodwaste (woodwaste already cut, but still in the field) and standing timber woodwaste. Corresponding bundles were created and capacities and indicative pricing information for these bundles were extracted from BC Hydro’s 2007 Request for Expressions of Interest (RFEOI). However, new guidelines being developed by the B.C. Ministry of Forests and Range may potentially increase or decrease the availability of woodwaste for power generation.

Biogas: The capital as well as operating and maintenance (O&M) costs associated with the biogas resource are heavily dependent on whether a gas collection system is already present or not. Two bundles - one with and one without collection - were created for potential projects. Additional power may be available from agricultural waste but is uncertain at this point.

MSW: MSW data consists of three proposed projects from the existing resource options database.

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39 In March 2007 BC Hydro released the RFEOI to assess and identify potential bioenergy projects and proponents for using residual wood, sawmill residues, logging debris and timber killed by the mountain pine beetle, for power production. BC Hydro received more than 80 responses in April 2007.
3.3.3.2 Results

The UECs are approximately 10 – 20 per cent higher than the 2005 ROR, primarily due to construction cost inflation and materials cost inflation. See Table 3-12 and Figure 3-6.

<table>
<thead>
<tr>
<th>Biomass Type</th>
<th>Number of Projects</th>
<th>Potential Capacity (MW)</th>
<th>Annual Energy (GWh/yr)</th>
<th>Dependable Capacity (MW)</th>
<th>Firm Energy (GWh/yr)</th>
<th>Weighted Average UEC @ 6% Discount Rate ($/MWh)</th>
<th>Weighted Average UEC @ 8% Discount Rate ($/MWh)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Sawmill Woodwaste</td>
<td>-</td>
<td>100</td>
<td>800</td>
<td>100</td>
<td>800</td>
<td>104</td>
<td>N/A</td>
</tr>
<tr>
<td>Roadside Woodwaste</td>
<td>-</td>
<td>200</td>
<td>1,600</td>
<td>200</td>
<td>1,600</td>
<td>132</td>
<td>N/A</td>
</tr>
<tr>
<td>Standing Timber Woodwaste</td>
<td>-</td>
<td>170</td>
<td>1,360</td>
<td>170</td>
<td>1,360</td>
<td>158</td>
<td>N/A</td>
</tr>
<tr>
<td>Municipal Solid Waste</td>
<td>1</td>
<td>51</td>
<td>408</td>
<td>51</td>
<td>408</td>
<td>88</td>
<td>97</td>
</tr>
<tr>
<td>Biogas with no Capture in place</td>
<td>9</td>
<td>8</td>
<td>64</td>
<td>8</td>
<td>61</td>
<td>63</td>
<td>68</td>
</tr>
<tr>
<td>Biogas with Capture in place</td>
<td>1</td>
<td>5</td>
<td>40</td>
<td>5</td>
<td>38</td>
<td>44</td>
<td>48</td>
</tr>
<tr>
<td><strong>TOTAL</strong></td>
<td></td>
<td><strong>534</strong></td>
<td><strong>4,272</strong></td>
<td><strong>534</strong></td>
<td><strong>4,267</strong></td>
<td></td>
<td></td>
</tr>
</tbody>
</table>

* 2008 costs including estimates for CIFT, line losses and a capacity credit. (See Appendix F11).
3.3.4 Wind

3.3.4.1 Methodology

In the case of wind, BC Hydro focused its update on cost and potential availability for four geographic areas of interest: 1) Vancouver Island; 2) North Coast (onshore and offshore); 3) Peace Region; and 4) Southern and Eastern Interior, as depicted in Figure 3-7.

The main rationale for the update is to address the increase in wind resource potential subsequent to the F2006 Call and increases in cost associated with turbines and supporting wind generation equipment. Also, BC Hydro undertook a review of the Southern and Eastern region of the province as there are many investigative use permits (IUPs)\textsuperscript{40} being requested or issued for this region. The update was supported with the assistance of an

\textsuperscript{40} IUPs are generally valid for two years and grant the right to conduct resource and environmental studies to determine the feasibility of a wind electricity generation project.
external consultant, GH. The methodology description provided by GH is set out in the report entitled “Assessment of the Energy Potential and Estimated Costs of Wind Energy in British Columbia” (February 2008), presented in Appendix F6.

3.3.4.2 Results

Table 3-13 and Table 3-14 provide an overview of the key findings and UECs.

<table>
<thead>
<tr>
<th>Wind Speed (m/s)</th>
<th>North Coast - Onshore</th>
<th>North Coast - Offshore</th>
<th>Peace Region</th>
<th>Vancouver Island</th>
<th>Southern &amp; Eastern Interior</th>
</tr>
</thead>
<tbody>
<tr>
<td>Wind Speed (m/s)</td>
<td>6.5 - 8.5</td>
<td>9.0 – 10.0</td>
<td>7.5 - 10.5</td>
<td>6.5 – 8.0</td>
<td>6.0 – 8.0</td>
</tr>
<tr>
<td>Potential (MW)</td>
<td>500</td>
<td>1,300</td>
<td>1,800</td>
<td>600</td>
<td>900</td>
</tr>
<tr>
<td>Generic Project Size (MW)</td>
<td>50</td>
<td>300</td>
<td>200</td>
<td>150</td>
<td>150</td>
</tr>
<tr>
<td># of Projects</td>
<td>10</td>
<td>4</td>
<td>9</td>
<td>4</td>
<td>6</td>
</tr>
<tr>
<td>Capacity Factor (%)</td>
<td>27 – 40</td>
<td>34 – 40</td>
<td>32 – 48</td>
<td>25 – 38</td>
<td>21 – 33</td>
</tr>
<tr>
<td>Avg. Annual Energy (GWh/yr)</td>
<td>1,600</td>
<td>4,400</td>
<td>6,500</td>
<td>1,600</td>
<td>2,300</td>
</tr>
<tr>
<td>Wind Type</td>
<td>Potential Capacity (MW)</td>
<td>Annual Energy (GWh/yr)</td>
<td>Weighted Average UEC @ 6% Discount Rate ($/MWh)</td>
<td>Weighted Average UEC @ 8% Discount Rate ($/MWh)</td>
<td></td>
</tr>
<tr>
<td>-----------</td>
<td>------------------------</td>
<td>------------------------</td>
<td>-----------------------------------------------</td>
<td>-----------------------------------------------</td>
<td></td>
</tr>
<tr>
<td>S&amp;E: LM Wind Bundle 1</td>
<td>24</td>
<td>67</td>
<td>108</td>
<td>128</td>
<td></td>
</tr>
<tr>
<td>S&amp;E: LM Wind Bundle 2</td>
<td>35</td>
<td>79</td>
<td>132</td>
<td>157</td>
<td></td>
</tr>
<tr>
<td>S&amp;E: SE Wind Bundle 1</td>
<td>69</td>
<td>189</td>
<td>108</td>
<td>128</td>
<td></td>
</tr>
<tr>
<td>S&amp;E: KLY Wind Bundle 1</td>
<td>73</td>
<td>201</td>
<td>108</td>
<td>128</td>
<td></td>
</tr>
<tr>
<td>S&amp;E: SE Wind Bundle 2</td>
<td>99</td>
<td>223</td>
<td>132</td>
<td>157</td>
<td></td>
</tr>
<tr>
<td>S&amp;E: KLY Wind Bundle 2</td>
<td>106</td>
<td>237</td>
<td>132</td>
<td>157</td>
<td></td>
</tr>
<tr>
<td>S&amp;E: EK Wind Bundle 1</td>
<td>137</td>
<td>378</td>
<td>108</td>
<td>128</td>
<td></td>
</tr>
<tr>
<td>S&amp;E: EK Wind Bundle 2</td>
<td>199</td>
<td>446</td>
<td>132</td>
<td>157</td>
<td></td>
</tr>
<tr>
<td>S&amp;E: NIC Wind Bundle 1</td>
<td>79</td>
<td>217</td>
<td>108</td>
<td>128</td>
<td></td>
</tr>
<tr>
<td>S&amp;E: NIC Wind Bundle 2</td>
<td>114</td>
<td>256</td>
<td>132</td>
<td>157</td>
<td></td>
</tr>
<tr>
<td><strong>Sub-total</strong></td>
<td><strong>935</strong></td>
<td><strong>2,293</strong></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>NC Offshore Wind Bundle 1</td>
<td>175</td>
<td>614</td>
<td>133</td>
<td>159</td>
<td></td>
</tr>
<tr>
<td>NC Offshore Wind Bundle 2</td>
<td>191</td>
<td>662</td>
<td>135</td>
<td>161</td>
<td></td>
</tr>
<tr>
<td>NC Offshore Wind Bundle 3</td>
<td>203</td>
<td>685</td>
<td>139</td>
<td>165</td>
<td></td>
</tr>
<tr>
<td>NC Offshore Wind Bundle 4</td>
<td>207</td>
<td>680</td>
<td>142</td>
<td>170</td>
<td></td>
</tr>
<tr>
<td>NC Offshore Wind Bundle 5</td>
<td>203</td>
<td>649</td>
<td>146</td>
<td>175</td>
<td></td>
</tr>
<tr>
<td>NC Offshore Wind Bundle 6</td>
<td>191</td>
<td>594</td>
<td>150</td>
<td>180</td>
<td></td>
</tr>
<tr>
<td>NC Offshore Wind Bundle 7</td>
<td>173</td>
<td>522</td>
<td>155</td>
<td>185</td>
<td></td>
</tr>
<tr>
<td><strong>Sub-total</strong></td>
<td><strong>1,343</strong></td>
<td><strong>4,406</strong></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>NC Onshore Wind Bundle 1</td>
<td>115</td>
<td>396</td>
<td>107</td>
<td>127</td>
<td></td>
</tr>
<tr>
<td>NC Onshore Wind Bundle 2</td>
<td>93</td>
<td>299</td>
<td>115</td>
<td>136</td>
<td></td>
</tr>
<tr>
<td>NC Onshore Wind Bundle 3</td>
<td>102</td>
<td>308</td>
<td>122</td>
<td>145</td>
<td></td>
</tr>
<tr>
<td>NC Onshore Wind Bundle 4</td>
<td>205</td>
<td>553</td>
<td>137</td>
<td>162</td>
<td></td>
</tr>
<tr>
<td><strong>Sub-total</strong></td>
<td><strong>515</strong></td>
<td><strong>1,556</strong></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Peace Wind Bundle 1</td>
<td>117</td>
<td>492</td>
<td>70</td>
<td>83</td>
<td></td>
</tr>
<tr>
<td>Peace Wind Bundle 2</td>
<td>232</td>
<td>947</td>
<td>72</td>
<td>86</td>
<td></td>
</tr>
<tr>
<td>Peace Wind Bundle 3</td>
<td>354</td>
<td>1,366</td>
<td>77</td>
<td>91</td>
<td></td>
</tr>
<tr>
<td>Peace Wind Bundle 4</td>
<td>408</td>
<td>1,476</td>
<td>82</td>
<td>96</td>
<td></td>
</tr>
<tr>
<td>Peace Wind Bundle 5</td>
<td>353</td>
<td>1,195</td>
<td>87</td>
<td>103</td>
<td></td>
</tr>
<tr>
<td>Peace Wind Bundle 6</td>
<td>342</td>
<td>1,053</td>
<td>96</td>
<td>113</td>
<td></td>
</tr>
<tr>
<td><strong>Sub-total</strong></td>
<td><strong>1,806</strong></td>
<td><strong>6,529</strong></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>VI Wind Bundle 1</td>
<td>127</td>
<td>416</td>
<td>93</td>
<td>110</td>
<td></td>
</tr>
<tr>
<td>VI Wind Bundle 2</td>
<td>102</td>
<td>312</td>
<td>100</td>
<td>118</td>
<td></td>
</tr>
<tr>
<td>VI Wind Bundle 3</td>
<td>112</td>
<td>320</td>
<td>107</td>
<td>126</td>
<td></td>
</tr>
<tr>
<td>VI Wind Bundle 4</td>
<td>226</td>
<td>571</td>
<td>120</td>
<td>142</td>
<td></td>
</tr>
<tr>
<td><strong>Sub-total</strong></td>
<td><strong>567</strong></td>
<td><strong>1,619</strong></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td><strong>TOTAL</strong></td>
<td><strong>5,166</strong></td>
<td><strong>16,403</strong></td>
<td></td>
<td></td>
<td></td>
</tr>
</tbody>
</table>
In some regions, UECs are 50 per cent or more higher than the 2005 ROR, primarily due to construction cost increases and material cost increases. In particular, wind power has experienced rapid development in the U.S, China and other areas of the world. The cost for wind turbines has increased significantly in recent months due to the increased demand for these machines. The potential energy assessment is higher than that contained within the results of the 2005 ROR due to:

- A fourth geographic region being included (Southern and Eastern); and
- The number of IUP sites has increased from just over 100 in early 2005 to over 250 in September 2007.

### 3.3.4.3 Wind Integration Costs

Wind energy generation resources are highly variable in the short time frame of minutes to hours, which makes it difficult to forecast energy delivery accurately. Due to its high variability, wind does not provide high levels of dependable capacity, and its generation cannot be committed firm to next day schedules in operation planning. Wind resources
require unique reserve requirements for regulation (minute to minute), load following (minutes to hours) and unit commitment/scheduling (hours to days) to compensate for sudden shift of wind power in real time and for scheduling next day to next week time horizon. Consequently, new wind resources will present new operating challenges for BC Hydro. While BC Hydro has a highly flexible hydro system which can be used to regulate the variability of new wind generation resources, regulation of the variability of wind resources introduces costs unique to the overall management of the hydro system.

To provide direction with respect to wind integration costs for the 2008 LTAP, BC Hydro performed an analysis of actual system requirements to integrate wind in B.C. and also undertook a jurisdictional review of wind integration studies performed by other utilities and organizations. The 2008 LTAP portfolios include a wind integration cost of $10/MWh. Further details on the wind integration costs can be found in Appendix F3. This is part of a larger study that BC Hydro is currently conducting to explicitly quantify these additional reserve requirements, their costs and any other impacts on BC Hydro system operation.

3.3.5 Geothermal

3.3.5.1 Methodology

The cost and resource potential of geothermal information in the 2005 ROR was updated by reviewing the current activities of the South Meager Geothermal project with the permit holder, Western GeoPower Corp. GeothermEx Inc., an independent consultant, concluded the South Meager Geothermal project has the potential to support up to a 100 MW plant. Also, publications, such as the “Green Energy Study for BC”, by BC Hydro Engineering (2002), “Electrical Potential in Northwest BC” by BCTC (2007) and “Potential improvements to Existing Geothermal Facilities in California” by Geothermal Research Council (2006) were reviewed.

3.3.5.2 Results

Table 3-15 provides the results of the geothermal ROU update:
Resource Options

Table 3-15  Geothermal UEC

<table>
<thead>
<tr>
<th>Geothermal Type</th>
<th>Number of Projects</th>
<th>Potential Capacity (MW)</th>
<th>Annual Energy (GWh/yr)</th>
<th>Dependable Capacity (MW)</th>
<th>Firm Energy (GWh/yr)</th>
<th>UEC Ave 6% Discount Rate ($/MWh)</th>
<th>UEC Ave 8% Discount Rate ($/MWh)</th>
</tr>
</thead>
<tbody>
<tr>
<td>South Meager Creek</td>
<td>1</td>
<td>100</td>
<td>800</td>
<td>100</td>
<td>800</td>
<td>59</td>
<td>68</td>
</tr>
</tbody>
</table>

1 3.3.6  Coal-Fired Generation

2 3.3.6.1  Scope/Methodology

Policy Action No. 20 of the 2007 Energy Plan stipulates that coal-fired generation must meet a zero GHG emission standard “through a combination of ‘clean coal’ fired generation technology, carbon sequestration and offsets for any residual GHG emissions”. BC Hydro obtained information on the current status of coal-fired generation with CCS by:

- Commissioning a study by Powertech;
- Reviewing literature published by National Resources Canada, the U.S. Department of Energy, and the Alberta Geological Survey; and
- A meeting was held with a representative of the Coal Association of Canada.

3.3.6.2  Results

Powertech’s report entitled “Clean Coal Power Generation by CO2 Sequestration” is presented in Appendix F2. Powertech concludes:

- At this time, the state of key components of CCS technology is such that it cannot be considered in commercial application of coal-fired generation. Although pilot plants are being considered and pursued, the viability of these technologies on a commercial application scale may not be known until 2017 or later.

- There is uncertainty with respect to the cost of CCS, and what impact CCS will have on a large coal-fired generation facility’s efficiency.
Although there are some geological sites in B.C. that may prove suitable for CO₂ storage, there is limited information available to assess the suitability for geological storage for CO₂ associated with utility scale coal-fired generation facilities at this time. Further studies need to be performed to understand the properties and behaviour of CO₂ at the temperature, pressure and stress conditions found in sedimentary basins in B.C.

There are legal, regulatory and public acceptance issues that likely need to be addressed before CO₂ CCS technology can be considered on a commercial scale in B.C.

Based on the above, Powertech recommended that BC Hydro not include coal-fired power generation with CCS as a commercial technology option in ROU. However, BC Hydro should continuously monitor developments in this area and include coal-fired power generation with CCS as a commercial option when appropriate. BC Hydro accepts these recommendations.

3.3.7 Natural Gas-Fired Generation

3.3.7.1 Methodology

The scope of activities undertaken in this update was as follows:

- Capital and operating costs for the various simple cycle gas turbine (SCGT) and combined cycle gas turbine (CCGT) projects identified in the 2005 ROR were updated.
- Capital and operating cost data were prepared for a new 100 MW SCGT project.
- Long term natural gas costs applicable to each project were updated based on the 2008 Natural Gas Price Forecast developed by Global Energy (and described in section 4.3).
- Heat rates, emission factors and other technical data were updated as appropriate.

AMEC was engaged to update the planning-level cost and technical data for the various SCGT and CCGT projects identified in the 2005 ROR. Based on information provided by AMEC, the resources options data sheet(s) for each project was updated. The approach taken by AMEC on capital costs was to develop factored cost estimates for key project components, and then update each component to current price levels using relevant
escalation indices. AMEC specifically obtained updated vendor budgetary quotes (e.g., from General Electric) for the cost of the various gas turbine generator packages which are a key component of each of these projects. Please see Appendix F7 for details.

AMEC was not asked to update the cost estimates or technical data for the basket of 300 MW of small cogeneration projects identified in the 2005 ROR. These estimates were updated by applying general Consumer Price Index (CPI) inflation and revised natural gas costs.

For the ROU, BC Hydro added the 100 MW SCGT project to the inventory of potential natural gas options. This was based on the rationale that the 100 MW unit size appeared more appropriate for BC Hydro’s system peaking requirements relative to previous SCGT unit size of approximately 40 MW. Also, indications were that unit costs for the 100 MW SCGT units would be substantially lower than for the 40 MW units.

3.3.7.2 Results

The key findings of the update were that UECs for natural gas projects are higher than the 2005 ROR, primarily due to:

- Cost of fuel increases;
- Construction, equipment and materials costs have increased due to inflation;
- Capacity and heat rates have been adjusted for degradation; and
- Fixed O&M costs have come down slightly:
  - Gas tolls have been removed from fixed O&M to avoid double counting.
  - Residual Fixed O&M costs are generally lower than those in the 2005 ROR.

A summary of the UEC components for the natural gas projects is provided in Table 3-16 and Table 3-17 for the medium and high gas price scenarios respectively. The summaries do not include GHG-related costs.
Table 3-16  Natural Gas Fired Generation UECs (Medium Gas Price)

<table>
<thead>
<tr>
<th>Gas Project</th>
<th>Number of Projects</th>
<th>Potential Capacity (MW)</th>
<th>Annual Energy (GWh/yr)</th>
<th>Dependable Capacity (MW)</th>
<th>Firm Energy (GWh/yr)</th>
<th>Medium Gas Price</th>
<th>UEC_6% ($/MWh)</th>
<th>UEC_8% ($/MWh)</th>
<th>UCC_6% ($/kW per year)</th>
<th>UCC_8% ($/kW per year)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Greenfield CCGT 500 MW</td>
<td>1</td>
<td>494</td>
<td>3,833</td>
<td>479</td>
<td>3,883</td>
<td>72</td>
<td>74</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Burrard Full CCGT - CC GT</td>
<td>1</td>
<td>1,100</td>
<td>8,798</td>
<td>1,100</td>
<td>8,798</td>
<td>72</td>
<td>73</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Burrard Half CCGT - CC GT</td>
<td>1</td>
<td>550</td>
<td>4,399</td>
<td>550</td>
<td>4,399</td>
<td>73</td>
<td>74</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Greenfield CCGT 250 MW</td>
<td>1</td>
<td>243</td>
<td>1,887</td>
<td>236</td>
<td>1,887</td>
<td>75</td>
<td>77</td>
<td></td>
<td></td>
<td></td>
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<tr>
<td>VI CCGT 500 MW</td>
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<td>494</td>
<td>3,831</td>
<td>479</td>
<td>3,831</td>
<td>81</td>
<td>83</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Small Cogen</td>
<td>1</td>
<td>300</td>
<td>2,400</td>
<td>300</td>
<td>2,400</td>
<td>85</td>
<td>88</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>VI CCGT 250 MW</td>
<td>1</td>
<td>243</td>
<td>1,887</td>
<td>236</td>
<td>1,887</td>
<td>84</td>
<td>87</td>
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<tr>
<td>Greenfield CCGT 50 MW</td>
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<td>391</td>
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<td>392</td>
<td>101</td>
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<tr>
<td>Greenfield SCGT 100 MW</td>
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<td>43</td>
<td>98</td>
<td>685</td>
<td>61</td>
<td>73</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Burrard SCGT A - F Class</td>
<td>1</td>
<td>514</td>
<td>3,602</td>
<td>514</td>
<td>3,602</td>
<td>66</td>
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<tr>
<td>LM SCGT 100 MW</td>
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<td>685</td>
<td>90</td>
<td>105</td>
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<tr>
<td>Burrard SCGT B - LMS 100</td>
<td>1</td>
<td>300</td>
<td>131</td>
<td>300</td>
<td>2,102</td>
<td>92</td>
<td>110</td>
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</tr>
<tr>
<td>Greenfield SCGT 40 MW</td>
<td>1</td>
<td>42</td>
<td>17</td>
<td>38</td>
<td>268</td>
<td>97</td>
<td>117</td>
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<td>VI SCGT 100MW</td>
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<td>685</td>
<td>147</td>
<td>162</td>
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<tr>
<td><strong>TOTAL</strong></td>
<td><strong>14</strong></td>
<td><strong>4,639</strong></td>
<td><strong>31,305</strong></td>
<td><strong>4,575</strong></td>
<td><strong>35,504</strong></td>
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Table 3-17  Natural Gas Fired Generation UECs (High Gas Price)

<table>
<thead>
<tr>
<th>Gas Project</th>
<th>Number of Projects</th>
<th>Potential Capacity (MW)</th>
<th>Annual Energy (GWh/yr)</th>
<th>Dependable Capacity (MW)</th>
<th>Firm Energy (GWh/yr)</th>
<th>High Gas Price</th>
<th>UEC_6% ($/MWh)</th>
<th>UEC_8% ($/MWh)</th>
<th>UCC_6% ($/kW per year)</th>
<th>UCC_8% ($/kW per year)</th>
</tr>
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<tbody>
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<td>3,833</td>
<td>479</td>
<td>3,883</td>
<td>101</td>
<td>102</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Burrard Full CCGT - CC GT</td>
<td>1</td>
<td>1,100</td>
<td>8,798</td>
<td>1,100</td>
<td>8,798</td>
<td>102</td>
<td>102</td>
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<td></td>
</tr>
<tr>
<td>Burrard Half CCGT - CC GT</td>
<td>1</td>
<td>550</td>
<td>4,399</td>
<td>550</td>
<td>4,399</td>
<td>102</td>
<td>103</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Small Cogen</td>
<td>1</td>
<td>300</td>
<td>2,400</td>
<td>300</td>
<td>2,400</td>
<td>104</td>
<td>107</td>
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<td></td>
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<tr>
<td>Greenfield CCGT 250 MW</td>
<td>1</td>
<td>243</td>
<td>1,887</td>
<td>236</td>
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<td>3,831</td>
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<td>111</td>
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<tr>
<td>VI CCGT 250 MW</td>
<td>1</td>
<td>243</td>
<td>1,887</td>
<td>236</td>
<td>1,887</td>
<td>114</td>
<td>116</td>
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<tr>
<td>Greenfield CCGT 50 MW</td>
<td>1</td>
<td>50</td>
<td>391</td>
<td>49</td>
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<tr>
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<td>98</td>
<td>685</td>
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<tr>
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<td>2,102</td>
<td>92</td>
<td>110</td>
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<tr>
<td>Greenfield SCGT 40 MW</td>
<td>1</td>
<td>42</td>
<td>17</td>
<td>38</td>
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<td>147</td>
<td>162</td>
<td></td>
<td></td>
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</tr>
<tr>
<td><strong>TOTAL</strong></td>
<td><strong>14</strong></td>
<td><strong>4,639</strong></td>
<td><strong>31,305</strong></td>
<td><strong>4,575</strong></td>
<td><strong>35,504</strong></td>
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</tr>
</tbody>
</table>
3.3.8 Large Hydro - Resource Smart Mica Unit 5 & 6 and Revelstoke Unit 6

3.3.8.1 Methodology

BC Hydro’s Resource Smart program, introduced in the late 1980s, promotes the identification, study and implementation of projects that provide cost-effective energy and capacity gains at existing BC Hydro facilities. The Resource Smart ROU focused on Mica Unit 5, Mica Unit 6 and Revelstoke Unit 6. These projects are primarily capacity projects as they are additional unit installations in existing reservoirs. Mica Unit 5 and Unit 6 will have installed capacities of approximately 500 MW each and provide a dependable capacity of 465 MW each. Revelstoke Unit 6 will have an installed capacity of approximately 500 MW and dependable capacity of 470 MW. These three generating units combined can contribute approximately 1,400 MW of winter dependable capacity and provide the BC Hydro system with additional system benefits.

* 2008 costs including estimates for CIFT, line losses, a capacity credit, GHG offset costs and carbon tax costs. (see Appendix F11).
The update of Mica Unit 5, Mica Unit 6 and Revelstoke Unit 6 involved revising the cost estimates for the projects. The ROU used a November 2007 cost update to determine the UCCs.

3.3.8.2 Results

The UCCs associated with the units used in the 2008 LTAP portfolio analysis are:

Table 3-18 Mica Unit 5, Mica Unit 6 and Revelstoke Unit 6 Costs

<table>
<thead>
<tr>
<th></th>
<th>Potential Capacity (MW)</th>
<th>Annual Energy (GWh/yr)</th>
<th>Dependable Capacity (MW)</th>
<th>Firm Energy (GWh/yr)</th>
<th>Weighted UCC Ave 6% Discount Rate ($/kW per Year)</th>
<th>Weighted UCC Ave 8% Discount Rate ($/kW per Year)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Mica Unit 5</td>
<td>500</td>
<td>130</td>
<td>465</td>
<td>130</td>
<td>58</td>
<td>75</td>
</tr>
<tr>
<td>Mica Unit 6</td>
<td>500</td>
<td>50</td>
<td>460</td>
<td>50</td>
<td>59</td>
<td>76</td>
</tr>
<tr>
<td>Revelstoke Unit 6</td>
<td>500</td>
<td>26</td>
<td>470</td>
<td>26</td>
<td>52</td>
<td>66</td>
</tr>
</tbody>
</table>

3.3.8.3 Additional Resource Smart Projects

There are six additional Resource Smart projects that together could potentially provide 259 GWh of energy and 109 MW of capacity: Lajoie Additional Unit, Duncan Dam New Generation, Kootenay Canal-Grohman Narrows, Ash River Additional Unit, Puntledge Additional Unit and Strathcona Additional Unit. With the exception of Duncan Dam, which is at the pre-feasibility stage, these Resource Smart projects are at the conceptual stage. All of these projects have a project lead time of six years with the exception of Kootenay Canal - Grohman Narrows Duncan Dam which has a lead time of four years. Due to the stage of development of these six Resource Smart projects they were not included in the portfolio analysis.

3.3.9 Site C

As currently defined, Site C would be located downstream from the existing Williston Reservoir and two existing BC Hydro generating facilities, GMS and Peace Canyon. Site C would provide 900 MW of dependable capacity and generate, on average, 4,600 GWh of energy annually. In terms of delivery, key characteristics of Site C include:
• Site C would deliver firm energy and capacity that would be highly flexible;

• Energy would be available during peak periods during the day and during the peak winter period;

• As the third project on one river system, Site C would optimize upstream storage and regulation;

• Minimal GHG impact once operational; and,

• Energy generated at Site C would be unaffected by fluctuations in natural gas costs that could affect other forms of energy supply.

3.3.9.1 Methodology

In December 2007, BC Hydro released the “Site C Feasibility Review: Stage 1 Completion Report”, a summary of which is attached as Appendix L1. The Stage 1 report provided the financial information required for the Site C ROU.

3.3.9.2 Results

Table 3-19, reproduced from the “Site C Feasibility Review: Stage 1 Completion Report”, provides a summary of the Site C financial costs.
### Table 3-19 Site C Stage 1 Report Costs

<table>
<thead>
<tr>
<th>Change in Discount and Interest Rates</th>
<th>150</th>
<th>300</th>
<th>450</th>
<th>600</th>
<th>750</th>
<th>900</th>
<th>1050</th>
</tr>
</thead>
<tbody>
<tr>
<td>A -2% $5.0 billion</td>
<td>$5.2 billion</td>
<td>$5.3 billion</td>
<td>$5.5 billion</td>
<td>$5.6 billion</td>
<td>$5.8 billion</td>
<td>$5.9 billion</td>
<td></td>
</tr>
<tr>
<td>$46 /MWh</td>
<td>$47 /MWh</td>
<td>$48 /MWh</td>
<td>$49 /MWh</td>
<td>$50 /MWh</td>
<td>$51 /MWh</td>
<td>$52 /MWh</td>
<td></td>
</tr>
<tr>
<td>B -1% $5.2 billion</td>
<td>$5.3 billion</td>
<td>$5.5 billion</td>
<td>$5.6 billion</td>
<td>$5.8 billion</td>
<td>$5.9 billion</td>
<td>$6.1 billion</td>
<td></td>
</tr>
<tr>
<td>$54 /MWh</td>
<td>$56 /MWh</td>
<td>$57 /MWh</td>
<td>$58 /MWh</td>
<td>$60 /MWh</td>
<td>$61 /MWh</td>
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<tr>
<td>C 0% $5.3 billion</td>
<td>$5.5 billion</td>
<td>$5.6 billion</td>
<td>$5.8 billion</td>
<td>$6.0 billion</td>
<td>$6.1 billion</td>
<td>$6.3 billion</td>
<td></td>
</tr>
<tr>
<td>$64 /MWh</td>
<td>$65 /MWh</td>
<td>$67 /MWh</td>
<td>$68 /MWh</td>
<td>$70 /MWh</td>
<td>$71 /MWh</td>
<td>$73 /MWh</td>
<td></td>
</tr>
<tr>
<td>D +1% $5.5 billion</td>
<td>$5.6 billion</td>
<td>$5.8 billion</td>
<td>$5.9 billion</td>
<td>$6.1 billion</td>
<td>$6.2 billion</td>
<td>$6.4 billion</td>
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</tr>
<tr>
<td>$74 /MWh</td>
<td>$76 /MWh</td>
<td>$77 /MWh</td>
<td>$79 /MWh</td>
<td>$81 /MWh</td>
<td>$83 /MWh</td>
<td>$85 /MWh</td>
<td></td>
</tr>
<tr>
<td>E +2% $5.7 billion</td>
<td>$5.8 billion</td>
<td>$6.0 billion</td>
<td>$6.1 billion</td>
<td>$6.3 billion</td>
<td>$6.4 billion</td>
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</tr>
<tr>
<td>$85 /MWh</td>
<td>$87 /MWh</td>
<td>$89 /MWh</td>
<td>$91 /MWh</td>
<td>$93 /MWh</td>
<td>$95 /MWh</td>
<td>$97 /MWh</td>
<td></td>
</tr>
<tr>
<td>F Project Cost (nominal)</td>
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<td></td>
</tr>
<tr>
<td>G Unit Cost (Cash) (F2008 $)</td>
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<td></td>
<td></td>
<td></td>
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<td></td>
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<tr>
<td>H Risk Reserve ($million)</td>
<td>750</td>
<td>900</td>
<td>1050</td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
</tbody>
</table>

1. **3.3.10 Waneta Expansion Project**

WAX is a project to construct a second powerhouse, adjacent to the Waneta Dam hydroelectric facility owned by TeckCominco Metals Limited on the Pend d’Oreille River just upstream from the confluence with the Columbia River near Trail, B.C., and a 10 km long, 230 kilovolt (kV) transmission line to BC Hydro’s Selkirk station. Columbia Power Corporation (CPC) and Columbia Basin Trust (CBT) own the rights to develop and construct additional generating facilities at the Waneta Dam.

WAX was assessed pursuant to both the B.C. *Environmental Assessment Act*[^41] (*BCEAA*) and the *Canadian Environmental Assessment Act*[^42] (*CEAA*), and received an Environmental Assessment Certificate (*EAC*) on 13 November 2007. In granting the EAC, the B.C. Ministers of Environment and Energy, Mines and Petroleum Resources noted that WAX is consistent with the Province’s goal to reduce GHG emissions. On May 1, 2008 the federal Minister of the Environment issued his decision and determined that the project “is not likely

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[^41]: S.B.C. 2002, c.43.
to cause significant adverse environmental effects”. Further the Minister of Environment has concluded that “no further environmental assessment by a review panel or a mediator is warranted”.

WAX will generate significant amounts of both energy and dependable capacity (predominantly in the months of April through July). Construction is targeted to commence in the spring of 2009. BC Hydro understands that WAX’s earliest ISD is 2013.

3.3.10.1 Methodology
CPC has publicly stated that WAX is anticipated to have a maximum of 435 MW. However, the project size (the MW of capacity) as may be specified under its currently planned RFP for construction is 335 MW. For this reason, BC Hydro has assumed a 335 MW plant size for purposes of the 2008 LTAP analysis.

3.3.10.2 Results
The UECs are  and  for 6 per cent and 8 per cent real discount rates respectively. The ultimate cost to, and value received by, BC Hydro would depend on the commercial terms for the acquisition of power from WAX, the system benefits that would be provided by WAX resulting from head gains and shaping benefits at Seven Mile and minor reductions in Seven Mile spill, as well as any other impacts WAX may have on the operation of the BC Hydro system.

3.3.11 Other Potential Large Hydro Projects
In addition to examining Site C, WAX and the potential for a pumped storage project on the Jordan River described below in section 3.3.12, BC Hydro updated information with respect to nine potential large hydroelectric projects investigated by BC Hydro in the past. These projects are Elaho, McGregor, Murphy Creek, Border, Homathko, Liard River, Iskut, High Site E and Low Site E. Three previously studied projects were removed from consideration due to legislation prohibiting their future development. These are Cutoff Mountain, Stikine and McGregor Diversion project.
3.3.11 Methodology

BC Hydro updated the information concerning the possible earliest ISDs of the nine potential large hydro projects and provided high level cost estimates for each of these nine large hydro projects. Details of this review are contained in Appendix F8.

3.3.11.2 Results

None of the nine potential large hydroelectric projects reviewed could be in-service prior to 2019, even if work were to commence on these projects in 2008. Site C continues to remain the most attractive large hydro resource option.

3.3.12 Pumped Storage – Jordan River, Generic and Lower Mainland Options

Pumped storage hydroelectric facilities use electricity generated during off-peak hours to pump water from a lower elevation reservoir to a higher elevation reservoir. This type of resource option usually does not provide firm energy. Pumped storage is usually built to acquire dependable capacity and meet peak load requirements: the water pumped and stored in the upper reservoir is released during peak demand periods. A pumped storage facility is a net energy consumer resulting in an efficiency of between 70 per cent and 75 per cent. The efficiency losses are attributed to equipment efficiencies and hydraulic losses during the pumping and generating cycles.

3.3.12.1 Methodology

A conceptual-level study was performed on the pump storage potential in the following regions:

- Vancouver Island - The Vancouver Island pumped storage option was developed to address the transmission capacity constraints on the Island. In 2001, BC Hydro commissioned a study to identify sites that would provide 200 MW of capacity with the least amount of environmental impact. The study was based on 43 pumped storage sites previously identified by BC Hydro in 1977. The results of the 2001 study concluded that the following three sites could potentially fill this resource option:
  - Shawnigan Lake – 200 MW, Comox Lake – 200 MW and Strathcona – 100 MW.
• Jordan River – Per Directive No. 21 of the 2006 IEP/LTAP Decision, the BCUC directed BC Hydro to include a pumped storage hydroelectric project on the Jordan River in its next ROU. BC Hydro addressed this directive from the following two perspectives:

- A general assessment of the pumped storage potential within the Jordan River watershed was undertaken. Details are provided in a BC Hydro Engineering Memo, dated November 8, 2007 and attached as Appendix F4a. The analysis concluded that there was a low potential for development of pumped storage hydroelectric projects using the existing reservoir system and that pumped storage at Jordan River was not desirable.

- BC Hydro engaged Powertech Labs to review a proposal submitted by Vanport Sterilizers Inc. (VPS). Details of this evaluation are contained within Appendix F4b. In summary, the VPS proposal was deemed not suitable for consideration as either a pumped storage or energy project. VPS was advised that should they wish to continue to pursue an energy project at this location, participation in a BC Hydro resource acquisition process would be appropriate.

• Lower Mainland – Generic pumped storage projects with installed capacities in the order of 1000 MW were evaluated based on information provided by IPPs with potential pumped storage sites in the Lower Mainland.

3.3.12.2 Results

The financial costs of potential pumped storage resource options were characterized by estimating direct capital cost and fixed O&M costs.

The pumped storage potential is summarized in Table 3-20.
Table 3-20  Pumped Storage Unit Capacity Costs

<table>
<thead>
<tr>
<th>Pumped Storage</th>
<th>Number of Projects (MW)</th>
<th>Potential Capacity (GWh/yr)</th>
<th>Annual Energy (GWh/yr)</th>
<th>Dependable Capacity (MW)</th>
<th>Firm Energy (GWh/yr)</th>
<th>UCC Ave 6% Discount Rate ($/kW per year)</th>
<th>UCC Ave 8% Discount Rate ($/kW per year)</th>
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</thead>
<tbody>
<tr>
<td>Vancouver Island</td>
<td>3</td>
<td>500</td>
<td>N/A</td>
<td>500</td>
<td>N/A</td>
<td>139</td>
<td>184</td>
</tr>
<tr>
<td>Lower Mainland</td>
<td>1</td>
<td>1,000</td>
<td>N/A</td>
<td>1,000</td>
<td>N/A</td>
<td>112</td>
<td>146</td>
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<tr>
<td>TOTAL</td>
<td>4</td>
<td>1,500</td>
<td>N/A</td>
<td>1,500</td>
<td>N/A</td>
<td></td>
<td></td>
</tr>
</tbody>
</table>

3.3.13  Canadian Entitlement

In the 2006 IEP/LTAP Decision, the BCUC directed BC Hydro to file a study in the next LTAP that identifies the level of firm transmission capacity available to deliver the CE to B.C. from the U.S. Also, the BCUC indicated that it is concerned that BC Hydro is overestimating the available capacity from reserve sharing and the CE. The BCUC Panel directed BC Hydro to address this issue in the next LTAP.

Further information on the CE curtailment risk and the challenges of flowing power through the Puget Sound Area can be found in the "Assessment of Puget Sound Area/Northern Intertie Curtailment Risk" report (Appendix P). This report notes, “It is important to acknowledge the system reinforcement and operating procedures that have been implemented to reduce the measured curtailment risk since 2003” (Appendix P, Page 1) and pending system reinforcements by December 2008 should help to further reduce curtailment risk (Appendix P, Page 26).

With the above system reinforcements, BC Hydro expects that only CE nominations above 1100 MW would face a curtailment risk. Further, after ten years, only nominations above 700 MW would face a curtailment risk under N-1 contingencies. This suggests the deliverability of CE will be relatively high, compared to forced outages of new capacity resources on the BC Hydro system.

3.3.14  Summary of Resource Options Update

The ROU has generally resulted in significantly higher UECs than the 2005 ROR, primarily due to construction and material cost increases. Additional assessment of IPP potential has resulted in the identification of additional potential energy with small hydro and wind. Also, a
review of the natural gas and coal technology has resulted in the addition of a 100 MW SCGT gas supply option and the removal of coal as a resource option.

In the 2005 ROR, BC Hydro presented UECs on a base level only. A concern was raised by stakeholders at that time that it is difficult to compare base UECs when there are other costs associated with resource options such as the cost of firm transmission, line losses, GHG offset costs, carbon tax, capacity credit and wind integration costs. As such, this ROU has shown an adjustment factor in the supply curves and table that include an “indicative allowance” for these additional cost factors. The adjustment factors applied to each resource type are explained in the previous respective sections in this chapter.

Figure 3-10 and Table 3-21 provide an overview of the resource option supply UEC values. A detailed table of UEC values can be found in Appendix F.
## Table 3-21 Resource Option Supply UEC Values

<table>
<thead>
<tr>
<th>Resource Type</th>
<th>Project Name</th>
<th>Average Annual Energy</th>
<th>UEC @ 6 % Real ($/MWh)</th>
<th>Total Adjusters[^3] ($)</th>
<th>Adjusted UEC ($/MWh)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Biomass</td>
<td>Biogas with capture</td>
<td>40</td>
<td>44</td>
<td>2</td>
<td>46</td>
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<tr>
<td>Small Hydro</td>
<td>LM Bundle 1</td>
<td>168</td>
<td>54</td>
<td>(1)</td>
<td>53</td>
</tr>
<tr>
<td>Geothermal</td>
<td>South Meager Creek</td>
<td>800</td>
<td>59</td>
<td>(4)</td>
<td>55</td>
</tr>
<tr>
<td>Biomass</td>
<td>Biogas with no Capture</td>
<td>64</td>
<td>63</td>
<td>-</td>
<td>63</td>
</tr>
<tr>
<td>Small Hydro</td>
<td>LM Bundle 2</td>
<td>458</td>
<td>65</td>
<td>(1)</td>
<td>64</td>
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<tr>
<td>Small Hydro</td>
<td>LM Bundle 3</td>
<td>898</td>
<td>75</td>
<td>(1)</td>
<td>74</td>
</tr>
<tr>
<td>Small Hydro</td>
<td>CI Bundle 1</td>
<td>142</td>
<td>74</td>
<td>8</td>
<td>82</td>
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<tr>
<td>Small Hydro</td>
<td>KLY Bundle 1</td>
<td>148</td>
<td>78</td>
<td>4</td>
<td>82</td>
</tr>
<tr>
<td>Biomass</td>
<td>Municipal Solid Waste</td>
<td>408</td>
<td>88</td>
<td>(6)</td>
<td>82</td>
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<tr>
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<td>LM Bundle 4</td>
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<td>84</td>
<td>-</td>
<td>84</td>
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<tr>
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<td>EK Bundle 1</td>
<td>95</td>
<td>75</td>
<td>9</td>
<td>84</td>
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<tr>
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<td>KLY Bundle 2</td>
<td>128</td>
<td>84</td>
<td>5</td>
<td>89</td>
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<td>89</td>
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<tr>
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<td>947</td>
<td>72</td>
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<td>83</td>
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<td>92</td>
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<td>37</td>
<td>97</td>
<td>(3)</td>
<td>94</td>
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<td>(1)</td>
<td>95</td>
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<td>13</td>
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<td>93</td>
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<td>100</td>
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<td>96</td>
<td>5</td>
<td>101</td>
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<tr>
<td>Wind</td>
<td>VI Wind Bundle 1</td>
<td>416</td>
<td>93</td>
<td>8</td>
<td>101</td>
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<tr>
<td>Wind</td>
<td>Peace Bundle 4</td>
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<td>94</td>
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<td>103</td>
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<tr>
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<td>Biomass</td>
<td>Sawmill Woodwaste</td>
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<td>105</td>
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<tr>
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<td>108</td>
<td>(3)</td>
<td>105</td>
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<tr>
<td><strong>Gas</strong></td>
<td><strong>Small Cogen</strong></td>
<td><strong>2,400</strong></td>
<td><strong>104</strong></td>
<td><strong>3</strong></td>
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</table>

[^3]: See Appendix F11 for an explanation on cost adders.
<table>
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<tr>
<th>Resource Type</th>
<th>Project Name</th>
<th>Average Annual Energy</th>
<th>UEC @ 6 % Real ($/MWh)</th>
<th>Total Adjusters(^43) ($)</th>
<th>Adjusted UEC ($/MWh)</th>
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<tbody>
<tr>
<td>Small Hydro</td>
<td>EK Bundle 3</td>
<td>88</td>
<td>96</td>
<td>11</td>
<td>107</td>
</tr>
<tr>
<td>Small Hydro</td>
<td>SE Bundle 2</td>
<td>128</td>
<td>97</td>
<td>10</td>
<td>107</td>
</tr>
<tr>
<td>Gas</td>
<td>Burrard Full CCGT-CCGT</td>
<td>8,798</td>
<td>102</td>
<td>6</td>
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<td>Wind</td>
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<td>1,195</td>
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<td>Gas</td>
<td>Burrard Half CCGT-CCGT</td>
<td>4,399</td>
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<tr>
<td>Wind</td>
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<td>100</td>
<td>8</td>
<td>108</td>
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<tr>
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<td>6</td>
<td>110</td>
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<td>NIC Bundle 3</td>
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<td>104</td>
<td>7</td>
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<td>114</td>
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<td>107</td>
<td>8</td>
<td>115</td>
</tr>
<tr>
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<td>NC Bundle 3</td>
<td>551</td>
<td>107</td>
<td>8</td>
<td>115</td>
</tr>
<tr>
<td>Gas</td>
<td>Greenfield CCGT 250MW</td>
<td>1,877</td>
<td>105</td>
<td>10</td>
<td>115</td>
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<tr>
<td>Wind</td>
<td>LM Bundle 1</td>
<td>67</td>
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<td>8</td>
<td>116</td>
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<tr>
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<td>EK Small Hydro 4</td>
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<td>VI CCGT 500MW</td>
<td>3,831</td>
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<td>6</td>
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<td>105</td>
<td>12</td>
<td>117</td>
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<tr>
<td>Wind</td>
<td>Peace Bundle 6</td>
<td>1,053</td>
<td>96</td>
<td>22</td>
<td>118</td>
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<tr>
<td>Gas</td>
<td>VI-CGGT 250MW</td>
<td>1,887</td>
<td>114</td>
<td>6</td>
<td>120</td>
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<td>KLY Wind Bundle 1</td>
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<td>108</td>
<td>26</td>
<td>124</td>
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<td>Wind</td>
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<td>108</td>
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<td>124</td>
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<td>Wind</td>
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<td>107</td>
<td>19</td>
<td>126</td>
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<td>Wind</td>
<td>VI Bundle 4</td>
<td>571</td>
<td>120</td>
<td>8</td>
<td>128</td>
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<tr>
<td>Wind</td>
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<td>189</td>
<td>108</td>
<td>22</td>
<td>130</td>
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<td>22</td>
<td>130</td>
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<td>NC Onshore Bundle 2</td>
<td>299</td>
<td>115</td>
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<td>135</td>
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<tr>
<td>Biomass</td>
<td>Roadside Woodwaste</td>
<td>1,600</td>
<td>132</td>
<td>3</td>
<td>135</td>
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<tr>
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<tr>
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<td>NC Onshore Bundle 3</td>
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<td>142</td>
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<tr>
<td>Gas</td>
<td>Greenfield CCGT 50MW</td>
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<td>143</td>
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<tr>
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<td>148</td>
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<tr>
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<td>NIC Bundle 2</td>
<td>256</td>
<td>132</td>
<td>18</td>
<td>150</td>
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</table>
### Resource Options

<table>
<thead>
<tr>
<th>Resource Type</th>
<th>Project Name</th>
<th>Average Annual Energy</th>
<th>UEC @ 6 % Real ($)/MWh</th>
<th>Total Adjusters$^4$ ($)</th>
<th>Adjusted UEC ($)/MWh</th>
</tr>
</thead>
<tbody>
<tr>
<td>Wind</td>
<td>NC Offshore Bundle 1</td>
<td>614</td>
<td>133</td>
<td>20</td>
<td>153</td>
</tr>
<tr>
<td>Wind</td>
<td>SE Bundle 2</td>
<td>223</td>
<td>132</td>
<td>24</td>
<td>156</td>
</tr>
<tr>
<td>Wind</td>
<td>EK Bundle 2</td>
<td>446</td>
<td>132</td>
<td>24</td>
<td>156</td>
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<tr>
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<td>553</td>
<td>137</td>
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<td>158</td>
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<tr>
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<td>NC Offshore Bundle 3</td>
<td>685</td>
<td>139</td>
<td>20</td>
<td>159</td>
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<tr>
<td>Biomass</td>
<td>Standing Timber</td>
<td>1,380</td>
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<td>3</td>
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<tr>
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<td>NC Offshore Bundle 5</td>
<td>649</td>
<td>146</td>
<td>20</td>
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<td>NC Offshore Bundle 6</td>
<td>594</td>
<td>150</td>
<td>21</td>
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<td>522</td>
<td>155</td>
<td>21</td>
<td>176</td>
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</table>

**Note:** Natural gas-fired options in the above table are based on the Global Energy high gas cost scenario described in section 4.3 and the medium GHG offset cost scenario described in section 4.2.

1. The capacity options available to BC Hydro are summarized in Table 3-22.

#### Table 3-22  Capacity Resource Option UCC Summary

<table>
<thead>
<tr>
<th>Capacity Option</th>
<th>Dependable Capacity (MW)</th>
<th>UCC @ 6 % ($/kW per year)</th>
<th>UCC @ 8 % ($/kW per year)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Revelstoke Unit 6$^a$</td>
<td>470</td>
<td>52</td>
<td>66</td>
</tr>
<tr>
<td>Mica Unit 5$^a$</td>
<td>465</td>
<td>58</td>
<td>75</td>
</tr>
<tr>
<td>Mica Unit 6$^a$</td>
<td>460</td>
<td>59</td>
<td>76</td>
</tr>
<tr>
<td>Greenfield SCGT 100 MW$^b$</td>
<td>98</td>
<td>61</td>
<td>73</td>
</tr>
<tr>
<td>Burrard SCGT A - F Class$^b$</td>
<td>514</td>
<td>66</td>
<td>79</td>
</tr>
<tr>
<td>LM SCGT (100 MW)$^b$</td>
<td>98</td>
<td>90</td>
<td>105</td>
</tr>
<tr>
<td>Burrard SCGT B - LMS 100$^b$</td>
<td>300</td>
<td>92</td>
<td>110</td>
</tr>
<tr>
<td>Greenfield SCGT 40 MW$^b$</td>
<td>38</td>
<td>97</td>
<td>117</td>
</tr>
<tr>
<td>Pumped Storage - LM$^b$</td>
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<td>146</td>
</tr>
<tr>
<td>Pumped Storage - VI$^b$</td>
<td>500</td>
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<td>185</td>
</tr>
<tr>
<td>VI SCGT (100MW)$^b$</td>
<td>98</td>
<td>147</td>
<td>162</td>
</tr>
</tbody>
</table>

$^a$ Based on November 2007 Cost Update.

$^b$ SCGT and pumped storage include fixed costs only.

2. As discussed in section 3.3.13, BC Hydro also has access to the capacity associated with the CE. For the reasons set out at section 2.3.10 this capacity is relied upon as a contingency resource, not a long-term planning option.

---

BC Hydro

3-37

[Revision 1 – February 27, 2009]
3.4 Transmission Resource Options

BCTC plans, manages and operates BC Hydro's transmission system. BCTC participated in establishing the transmission resource options in the 2008 LTAP by providing information for major bulk transmission system upgrades potentially required by various supply portfolios at each of the cut-planes. BCTC supported the LTAP portfolio development process by indicating which transmission resource option should be included in each of the LTAP portfolios and the required timing for when the transmission options should be planned for. The cost of the transmission options are then included in the portfolio cost.

Figure 3-11 provides an overview of the transmission system and cut-planes. In this diagram the red lines indicate the existing 500 kV transmission lines, the green lines indicate the 230 kV transmission lines, the blue lines indicate the 138 kV transmission lines and the black lines cutting across the red transmission lines are the cut-planes indicating the areas of congestion for which the basket of transmission resource options were identified. The direction of arrow indicates the transfer of power from the supply side of the cut plane towards the load side.
For the 2008 LTAP ROU, BCTC provided Table 3-23 identifying transmission reinforcement options, brief descriptions, earliest ISDs, direct capital costs and cost accuracies. These cost estimates do not include overhead, interest during construction, escalation or inflation costs.
<table>
<thead>
<tr>
<th>Item number</th>
<th>Reinforcement Option</th>
<th>Earliest In Service Date</th>
<th>Direct Cost 2007 ($ millions)</th>
<th>Cost Accuracy (%)</th>
</tr>
</thead>
<tbody>
<tr>
<td>1</td>
<td>Nicola Substation 500 kV reconfiguration</td>
<td>October 2013</td>
<td>9</td>
<td>-50 to +100</td>
</tr>
<tr>
<td>2</td>
<td>Series compensation of 50 per cent on Selkirk to Ashton Creek 500 kV line (5L91) and Vaseux Lake to Nicola 500 kV line (5L98)</td>
<td>October 2011</td>
<td>50</td>
<td>-15 to +35</td>
</tr>
<tr>
<td>3</td>
<td>500 kV 250 MVAr Nicola shunt capacitor # 1</td>
<td>October 2011</td>
<td>5</td>
<td>-15 to +35</td>
</tr>
<tr>
<td>4</td>
<td>Selkirk to Vaseux Lake 500 kV line (5L97) with 50 per cent series compensation</td>
<td>October 2017</td>
<td>202</td>
<td>-35 to +100</td>
</tr>
<tr>
<td>5</td>
<td>Nicola to Vaseux Lake 500 kV line (5L99) with 50 per cent series compensation</td>
<td>October 2017</td>
<td>175</td>
<td>-35 to +100</td>
</tr>
<tr>
<td>6</td>
<td>Series compensation of 50 per cent on Mica to Nicola 500 kV lines (5L71 and 5L72).</td>
<td>October 2017</td>
<td>41</td>
<td>-50 to +100</td>
</tr>
<tr>
<td>7</td>
<td>Series compensation of 50 per cent 3000 A on Nicola to Ashton Creek and Vaseux Lake to Selkirk 500 kV lines (5L76, 5L79 and 5L96).</td>
<td>October-2017</td>
<td>56</td>
<td>-15 to +35</td>
</tr>
<tr>
<td>8</td>
<td>Nicola to Meridian 500 kV line (5L83) with 50 per cent series compensation</td>
<td>October 2013</td>
<td>426</td>
<td>-10 to +30</td>
</tr>
<tr>
<td>9</td>
<td>Kelly Lake to Cheekye 500 kV line (5L46) with 50 per cent series compensation.</td>
<td>October 2017</td>
<td>314</td>
<td>-35 to +100</td>
</tr>
<tr>
<td>10</td>
<td>500 kV – 100 to + 150 MVAr Ingledow SVC</td>
<td>October 2014</td>
<td>31</td>
<td>-35 to +100</td>
</tr>
<tr>
<td>11</td>
<td>220 kV 2 x 110 MVAr Meridian shunt capacitors</td>
<td>October 2011</td>
<td>4</td>
<td>-15 to +35</td>
</tr>
<tr>
<td>12</td>
<td>Kelly Lake Substation 500 kV reconfiguration</td>
<td>October 2011</td>
<td>9</td>
<td>-15 to +35</td>
</tr>
<tr>
<td>Item number</td>
<td>Reinforcement Option</td>
<td>Earliest In Service Date</td>
<td>Direct Cost 2007 ($ millions)</td>
<td>Cost Accuracy (%)</td>
</tr>
<tr>
<td>-------------</td>
<td>---------------------------------------------------------------------------------------</td>
<td>--------------------------</td>
<td>-------------------------------</td>
<td>-------------------</td>
</tr>
<tr>
<td>13</td>
<td>500 kV 250 MVAr Kelly Lake shunt capacitor #1</td>
<td>October 2014</td>
<td>5</td>
<td>-15 to +35</td>
</tr>
<tr>
<td>14</td>
<td>500 kV 250 MVAr Williston shunt capacitor #1</td>
<td>October 2014</td>
<td>5</td>
<td>-15 to +35</td>
</tr>
<tr>
<td>15</td>
<td>500 kV 250 MVAr Williston shunt capacitor #2</td>
<td>October 2014</td>
<td>5</td>
<td>-15 to +35</td>
</tr>
<tr>
<td>16</td>
<td>500 kV 300 MVAr Williston SVC #1</td>
<td>October 2014</td>
<td>43</td>
<td>-35 to +100</td>
</tr>
<tr>
<td>17</td>
<td>GMS to Williston 500 kV fourth transmission line (5L8) with 50 per cent series compensation</td>
<td>October 2017</td>
<td>346</td>
<td>-35 to +100</td>
</tr>
<tr>
<td>18</td>
<td>Williston to Kelly 500 kV fourth transmission line (5L14) with 50 per cent series compensation</td>
<td>October 2017</td>
<td>304</td>
<td>-35 to +100</td>
</tr>
<tr>
<td>19</td>
<td>Series compensation upgrade at Kennedy from 50 per cent to 65 per cent on GMS to Williston 500 kV lines 5L1, 5L2, 5L3 and 5L7 with thermal upgrades to 3000 A rating.</td>
<td>October 2014</td>
<td>53</td>
<td>-35 to +100</td>
</tr>
<tr>
<td>20</td>
<td>Series compensation upgrade at McLees from 50 per cent to 65 per cent on Williston to Kelly 500 kV lines 5L11, 5L12 and 5L13 with thermal upgrades to 3000 A rating.</td>
<td>October 2014</td>
<td>51</td>
<td>-35 to +100</td>
</tr>
<tr>
<td>21</td>
<td>Series compensation of 35 per cent 1025 A on Williston to Glennanan 500 kV line (5L61).</td>
<td>October 2014</td>
<td>14</td>
<td>-50 to +100</td>
</tr>
</tbody>
</table>

1 Estimates Uncertainty and Qualifiers: The transmission upgrades along with their cost estimates are dependent on many factors. For example, the scope of work may not be well defined, the ISD and market prices may change, and project risks may not be adequately addressed. As a consequence, actual costs and schedules may materially differ from those estimated.
For purposes of this 2008 LTAP, BCTC and BC Hydro have developed a common set of transmission planning assumptions that are contained in Appendix F9.

3.5 Financial Assumptions

3.5.1 Cost of Capital

BC Hydro’s corporate discount rate policy was revised in January 2008 to align with the amended definition of BC Hydro’s equity included in HSD#1 and HSD#2 (see section 1.2.3).

The corporate discount rate policy provides that BC Hydro utilize a Nominal Weighted Average Cost of Capital (WACC)/Discount Rate of eight per cent based on the information in Table 3-24.

<table>
<thead>
<tr>
<th>Table 3-24</th>
<th>BC Hydro Discount Rate</th>
</tr>
</thead>
<tbody>
<tr>
<td>Cost of Equity (nominal)</td>
<td>11.78%</td>
</tr>
<tr>
<td>Cost of Debt (nominal)</td>
<td>6.00%</td>
</tr>
<tr>
<td>Equity component in capital structure</td>
<td>30%</td>
</tr>
<tr>
<td>Debt component in capital structure</td>
<td>70%</td>
</tr>
<tr>
<td>Project WACC/discount rate</td>
<td>7.73%, rounded to 8% nominal</td>
</tr>
</tbody>
</table>

A nominal discount rate of eight per cent was utilized in the ROU. Due to its long term planning nature, the 2008 LTAP update simplifies the variation in the annual CPI forecast to assume an average annual inflation rate of two per cent throughout 2008 LTAP’s 20-year planning horizon. The forecast CPI applied to the BC Hydro corporate cost of capital/discount rate provides a 6 per cent real discount rate (rounded) for 2008 LTAP analysis.

Similar to the 2006 IEP/LTAP, for purposes of the UEC and UCC sensitivity analysis, BC Hydro used real discount rate scenarios set at eight per cent and six per cent.

In the portfolio analysis, a sensitivity analysis was completed with a real cost of capital of eight per cent and a real discount rate of six per cent; as well as a real cost of capital of eight per cent and a real discount rate of eight per cent.
3.5.2 Rate Impact Methodology

As set out in section 1.2.4, the long term financial rate forecast methodology will be set out in a report to be filed with the BCUC either before or as part of BC Hydro’s responses to BCUC and Intervenor Information Request No. 1.

3.5.3 Resource Option Cost Escalation

The ROU provides the real 2008 costs of the various resource options. However, in the 2008 LTAP portfolio modelling process, these resources may be selected to fill the load/resource gap at any time during the planning horizon. Therefore, there is a need to estimate real escalation rates that can be applied to the resource option costs to update the real costs to the time period when the resource option is selected in the 2008 LTAP portfolio.

The 2008 LTAP cost escalation adheres to BC Hydro’s construction outlook. This outlook is recommended for the planning of BC Hydro capital projects that have significant construction components in project capital costs. The BC Hydro engineering outlook is a summary recommendation based on a MMK Consulting Inc. (MMK) report which is updated semi-annually. The 2008 LTAP portfolio modelling is based on the September 2007 outlook.

The 2008 LTAP cost escalation addresses cost pressure on construction activities only; therefore, it is necessary to identify the capital cost components of resource option costs that are construction-related. The break-down of construction-related capital costs from total capital costs is done at a resource type level (wind, geothermal, small hydro, large hydro, natural gas fired generation, bioenergy) rather than at a project-specific level. These estimates of construction-related capital costs are based on the information from various technical reports that formed the basis of the ROU, and are consistent with the assumptions supporting the resource options’ UEC derivation. A cost escalation adjustment was made specifically for wind turbines, based on ROU study findings.

Table 3-25 shows the escalation rates that are applied to the total capital costs of the resource options for the 2008 LTAP when building portfolios.
Table 3-25 Resource Options Escalation Rates

<table>
<thead>
<tr>
<th>Resource / Source</th>
<th>2008</th>
<th>2009</th>
<th>2010</th>
<th>2011</th>
<th>2012</th>
<th>2013 Onwards</th>
</tr>
</thead>
<tbody>
<tr>
<td>BCH Engineering Estimates</td>
<td>3.25%</td>
<td>3.00%</td>
<td>2.25%</td>
<td>1.25%</td>
<td>1.00%</td>
<td>1.00%</td>
</tr>
<tr>
<td>Large Hydro</td>
<td>3.25%</td>
<td>3.00%</td>
<td>2.25%</td>
<td>1.25%</td>
<td>1.00%</td>
<td>1.00%</td>
</tr>
<tr>
<td>Small Hydro</td>
<td>2.60%</td>
<td>2.40%</td>
<td>1.80%</td>
<td>1.00%</td>
<td>0.80%</td>
<td>0.80%</td>
</tr>
<tr>
<td>Wind</td>
<td>4.65%</td>
<td>4.60%</td>
<td>4.45%</td>
<td>4.25%</td>
<td>4.20%</td>
<td>1.00%</td>
</tr>
<tr>
<td>CCGT/SCGT/Co-gen</td>
<td>1.95%</td>
<td>1.80%</td>
<td>1.35%</td>
<td>0.75%</td>
<td>0.60%</td>
<td>0.60%</td>
</tr>
<tr>
<td>Biomass</td>
<td>3.25%</td>
<td>3.00%</td>
<td>2.25%</td>
<td>1.25%</td>
<td>1.00%</td>
<td>1.00%</td>
</tr>
<tr>
<td>Geothermal</td>
<td>3.25%</td>
<td>3.00%</td>
<td>2.25%</td>
<td>1.25%</td>
<td>1.00%</td>
<td>1.00%</td>
</tr>
<tr>
<td>Transmission Projects</td>
<td>3.25%</td>
<td>3.00%</td>
<td>2.25%</td>
<td>1.25%</td>
<td>1.00%</td>
<td>1.00%</td>
</tr>
</tbody>
</table>

3.5.4 UEC and UCC methodology

The UEC and UCC provide a measure of the costs of a supply option per unit of energy or capacity from the respective supply option. These values serve as an initial ranking of energy and capacity resources in scheduling resources to fill a load/resource gap. The general methodology for energy resource unit costing in the 2008 LTAP is the same as that in the 2006 IEP/LTAP.

3.5.5 Exchange Rate Forecast

In the 2008 LTAP, BC Hydro continues to reflect the economic outlook that is consistent with that from the B.C. Ministry of Finance (MoF), as presented in its 2008 Provincial Budget (issued January 2008). The MoF provides its financial forecasts over a five-year horizon. This short term forecast forms the basis of the first five years of the 2008 LTAP planning horizon and extends the last forecast year of the MoF’s five-year forecast (F2013) to the rest of the LTAP evaluation period.

To address BCUC’s concerns on the 2007 Alcan EPA review process, scenario analyses to provide uncertainty bands of +/- ten per cent on the long term exchange rate forecast spanning F2014 to F2027 are included in Chapter 5.

Table 3-26 Exchange Rates

<table>
<thead>
<tr>
<th></th>
<th></th>
<th></th>
<th></th>
<th></th>
<th></th>
</tr>
</thead>
<tbody>
<tr>
<td>Canadian Dollars Stated in U.S. Dollars</td>
<td>$0.99</td>
<td>$0.95</td>
<td>$0.94</td>
<td>$0.93</td>
<td>$0.93</td>
</tr>
</tbody>
</table>

---

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4.1 Introduction

This Chapter of the Application examines the major external influences of both government policy and regulatory initiatives, and the power industry marketplace, in BC Hydro’s long-term resource planning since the 2006 IEP/LTAP. More specifically, as part of Step 4 (see Figure 1-1) in the 2008 LTAP update, BC Hydro assessed:

- The developing GHG regulatory environment. Section 4.2 reviews and summarizes relevant GHG legislative and policy developments since the 2006 IEP/LTAP Decision, and sets out an updated GHG price forecast for 2008-2050;

- Natural gas (section 4.3) and electricity prices (section 4.4). In the intervening two years since the 2006 IEP/LTAP, natural gas and electricity markets are exhibiting upward trends. Fuel prices, particularly natural gas, are a major driver of WECC wholesale electricity market prices and they strongly affect the economics of new generation resources that may be considered by utilities; and

- The RPS requirements in the U.S. portion of WECC, and the eligibility of B.C.-based renewables supply under various U.S. state RPS, in section 4.5. A forecast of the incremental value of the RECs associated with renewable electricity generation is provided in that section.

BC Hydro has improved the methodologies it applied in its analysis of the relevant markets and related factors that impact its long-term resource planning. In preparing its GHG, natural gas price, and clean and renewable market forecasts, BC Hydro elicited the services of third party experts, and in particular with respect to both the GHG and natural gas price forecasts, asked these experts to assign probabilities to those forecasts. Natsource prepared the 2007 Greenhouse Gas Offset Forecast Report for BC Hydro, December 1, 2007 which appears at Appendix G1 to this application. Natsource assigned probabilities to the main GHG policy scenarios in its memorandum entitled “Probabilities for scenarios in Natsource’s 2007 Greenhouse Gas Offset Forecast Report”, attached as Appendix G3.

Global Energy prepared the report entitled Natural Gas Price Forecasts for BC Hydro that is included at Appendix I. As described in section 1.2.6, Global Energy utilized three internally consistent, fundamentals-based scenarios of future market conditions it previously
developed for the CEC as part of the CEC’s IEPR process. As a result of Global Energy’s
development of a High Gas Price Forecast and assignment of probabilities to the three
Global Energy natural gas price forecasts, in the 2008 LTAP BC Hydro has not relied on the
three natural gas price scenarios previously used in the 2006 IEP/LTAP, namely its
internally generated High Gas scenario, the U.S. Energy Information Administration (EIA)
forecast and the Confer Consulting Long Run Marginal Cost case. BC Hydro has also
discontinued the use of an equally weighted average of forecasts used in its analysis. In
addition, for the first time the electricity price forecast incorporates GHG offset costs.

4.2 Greenhouse Gas Offset Price Forecast

4.2.1 Introduction

Utilities face two distinct sets of risks related to global climate change. One set, which is
addressed in this section and Appendix G, are the financial risks associated with GHG
regulatory actions. A second set, which will be addressed in the next LTAP in accordance
with Directive 6 of the BCUC’s 2006 IEP/LTAP Decision, are the risks associated with
climate change itself, such as the physical impacts of climate change on electricity
generation.

The 2006 IEP/LTAP recognized the potential for government-imposed costs associated with
GHG policy. In the intervening two years, the B.C. Government and a number of U.S. states
have implemented mandatory targets for GHG reduction. The Canadian Federal
Government is currently in the process of introducing regulations under the Canadian
Environmental Protection Act\(^45\) (**CEPA**) to set mandatory GHG reduction targets and the
U.S. Congress also plans to legislate GHG reduction goals. These legislative initiatives are
expected to establish and influence the market price for GHGs through such regulatory
mechanisms as emissions trading and GHG offset programs.\(^46\) In turn, regulatory responses

\(^{45}\) S.C. 1999, c.33.

\(^{46}\) In this application, a GHG offset is considered a real, verifiable and additional reduction of GHG emissions, or
removal of GHG from the atmosphere, that is established, approved or recognized by B.C. or Canadian
regulation as an offset. The purpose of an offset is typically to achieve a cost-effective reduction of total GHG
emissions by decreasing emissions from a source or activity not covered under emissions reduction regulatory
programs and attributing (or crediting) the reduction to another, regulated source or activity. For example,
reducing methane emissions from landfill sites may be considered an offset for a thermal generation plant if
this activity is not already covered under an emissions trading program and is not required to occur under
command and control regulations.
to limit GHGs are also expected to significantly affect the costs, market value and risk
associated with the evaluation of electricity generation resource options by utilities.

This section provides an overview of the emerging regulatory and policy developments
considered in the Natsource GHG price forecast, and the implications of those
developments for the 2008 LTAP. The section is structured as follows:

- Section 4.2.2 provides a general overview of the key regulatory and policy developments
  in B.C., Canada and the U.S. subsequent to the finalization of the Natsource GHG price
  forecast report, dated December 1, 2007;

- Section 4.2.3 sets out the three policy scenarios used to frame the GHG price forecast
  and two sensitivity cases describing potential near-term policy outcomes influencing
  prices in B.C., and summarizes the results of the GHG price forecast scenarios and
  probability analysis; and

- Section 4.2.4 describes how the GHG price forecasts are incorporated into the 2008
  LTAP analysis.

Additional details regarding GHG pricing assumptions, methodology and a comparison of
BC Hydro's GHG price forecast to forecasts used by other electric utilities in integrated
resource planning is found in the Natsource GHG price forecast report attached as
Appendix G1.

4.2.2 GHG Regulatory and Policy Developments

BC Hydro retained Natsource to update the GHG price forecast prepared for the 2006
IEP/LTAP Application. Natsource reviewed developments in GHG regulatory policy in B.C.,
Canada and the U.S. (federal and state-level). Part II of the Natsource GHG price forecast
report contains a description of the legislative and policy initiatives to limit GHG emissions.
These GHG-related developments reinforce Natsource's and BC Hydro's view that a
scenario in which the price of GHGs would be zero is not foreseeable. The remainder of this
section updates these initiatives.
4.2.2.1 Canada - Federal Regulatory Framework

On March 10, 2008, the Federal Government announced further details of proposed GHG emissions regulations\(^{47}\) to be enacted under CEPA. The March 2008 Regulatory Framework confirmed intensity-based GHG reduction targets of 18 per cent by 2010, with a 2 per cent continuous improvement every year after that, for regulated industries such as electricity generation produced by combustion. Four compliance mechanisms are available: in-house reductions, contributions to a Technology Fund,\(^{48}\) acquiring offsets\(^{49}\) and receiving credit for early action. From 2010 to 2012, the contribution rate for the Technology Fund would be $15 per tonne of CO\(_2\)e. In 2013, the contribution rate would be $20 per tonne. Thereafter, the rate would escalate yearly at the rate of growth of nominal GDP to 2017. Environment Canada would administer the offset system and will approve project protocols, register projects submitted by proponents, certify the reductions and issue offset credits. Guidance documents for protocol developers, project proponents and verification bodies will be published during the summer of 2008.

The federal GHG emissions regulations will also set a coal-fired generator standard equivalent to CCS. The regulations will apply to coal-fired generators coming on stream in 2012 or after, and will come into force in 2018. The GHG emission regulations are expected to be published in the Canada Gazette later this year, and the regulations finalized in 2009 to come into force on January 1, 2010.

4.2.2.2 Province of British Columbia

There have been several B.C. Government legislative developments:\(^{50}\)


\(^{48}\) Contributions to the Technology Fund would be limited to 70 per cent of the target in 2010, falling to 65 per cent in 2011, 60 per cent in 2012, 55 per cent in 2013, 50 per cent in 2014, 40 per cent in 2015, 10 per cent in 2016 and 10 per cent in 2017. No further contributions would be accepted after 2017. The research and development component, which would focus on projects aimed at supporting the creation of transformative technologies, would be limited to 5 Megatonnes each year, also ending after 2017.

\(^{49}\) This includes unlimited access to domestic (made in Canada) offset projects and certain credits from the Kyoto Protocol's Clean Development Mechanism (CDM). Access to CDM credits for compliance purposes would be limited to 10 per cent of each firm's total target.

\(^{50}\) Additional GHG-related legislative developments not described in this section are the 2008 Greenhouse Gas reduction (Renewable and Low Carbon Fuel Requirements) Act, and the Greenhouse Gas Reduction (Vehicle Emissions Standards) Act. The former Act creates a regulatory framework to enable the Province to create... Footnote continued on next page.
• On January 1, 2008 the Greenhouse Gas Reduction Targets Act (GGRTA) was brought into force.\(^{51}\) GGRTA sets into law B.C.’s GHG emissions target of at least 33 per cent below 2007 levels by 2020, and at least 80 per cent below 2007 levels by 2050. Interim GHG targets for 2012 and 2016 are to be set by the end of 2008;

• The Province of B.C. has joined the WCI, a partnership of seven U.S. states and the provinces of B.C., Manitoba and Quebec. This commitment includes participation in the design and implementation of a GHG emission trading system.\(^{52}\) On May 29, 2008, the Greenhouse Gas Reduction (Cap and Trade) Act (GHG Cap and Trade Act),\(^{53}\) received Royal Assent, but comes into force by regulation. The purpose of the GHG Cap and Trade Act is to enable the reductions of GHG emissions through a cap-and-trade system. The GHG Cap and Trade Act establishes compliance obligations for regulated operations in B.C. to determine GHG emissions, ensure compliance is met through the retirement of sufficient compliance units, and report emissions and compliance actions. The GHG Cap and Trade Act establishes three mechanisms for compliance (compliance units) - (1) allowances, (2) reductions and (3) recognized compliance units from other cap-and-trade systems - and sets out requirements for a tracking system for compliance units. Virtually all of the details are left to regulations. For example, among other things, regulations are to establish: (1) the regulated operations; (2) the method of allocating allowances to entities (e.g. free of charge or through auctions); (3) the compliance units, and in particular what the geographic scope of out-of-Provence compliance units will be; (4) the compliance unit tracking system; and (5) whether GHG emissions associated with imports are to be regulated. Pursuant to section 39(c), the B.C. Government may deem GHG emissions outside B.C. to be attributable to a regulated operation and “in relation to electricity, [deem] [GHG] emissions associated with generation and transmission of the electricity until the point at which the electricity is received by the British Columbia electricity grid to be attributable” to a regulated operation. The GHG Cap and Trade Act contemplates eventual linkage of the B.C. cap and trade system to other systems, such as renewable-content and low-carbon specifications for transportation fuel. The latter Act creates a new regulatory structure to reduce GHG emissions by requiring motor vehicle manufacturers to have their vehicle fleets meet a prescribed fleet emissions standard. Neither Act is relevant to the 2008 LTAP.


\(^{53}\) S.B.C. 2008, c.32.
as WCI. This is evidenced by the definition of “recognized compliance units” as units from
another system that are recognized under the GHG Cap and Trade Act and by the
provision that the compliance unit tracking system may be linked by regulation to another
comparable system. The framework of the WCI GHG cap-and-trade system is expected
by August 2008,\(^{54}\) for implementation by partner jurisdictions by 2012;

- On May 29, 2008 the Emissions Standards Act received Royal Assent; section 2, the
relevant section, comes into force by regulation. As set out in Table 1-2 in section 1.2.3,
\textbf{Bill 31—Emissions Standards Act} amends EMA as follows. Prescribed coal-fired
generators will be required to capture and sequester GHG emissions from the
combustion of coal. New electricity generation facilities, and prescribed expansions to
existing facilities, that use fossil fuel other than coal will be subject to the “net zero” GHG
requirement as soon as the Emissions Standards Act comes into force. Net zero GHG
emissions means that such facilities must use offsets to balance their GHG emissions.
Existing facilities that use fossil fuel other than coal will be given until 2016 to become net
zero; and

- The Carbon Tax Act received Royal Assent on May 29, 2008, and comes into force on
July 1, 2008. Pursuant to OIC No. 387,\(^{55}\) the Carbon Tax Act is applicable to BC Hydro.
The Carbon Tax Act imposes the revenue neutral carbon tax announced on
February 19, 2008 as part of the B.C. Government’s budget. The tax would apply to
virtually all fossil fuels within the B.C., including natural gas, coal, diesel fuel, gasoline,
propane and home heating oil. The level of the carbon tax has been set at $10 per tonne
of associated CO\(_2\) or CO\(_2\)e, emissions, starting on July 1, 2008. Natsource\(^{56}\) confirmed
that the proposed carbon tax does not undermine the assumptions made in the
development of the scenarios or the GHG price forecast, because the carbon tax signals
of $10 per tonne of associated CO\(_2\) and the subsequent increase of $5 per year to
$30 per tonne of associated CO\(_2\) are for purposes of setting the rate of the carbon tax
within B.C., not offsets or cap-and-trade compliance mechanisms. Pursuant to section 84
of the Carbon Tax Act, the B.C. Cabinet may with respect to a fuel or combustible that is

\(^{54}\) Western Climate Initiative website. \url{http://www.westernclimateinitiative.org/}.
\(^{55}\) Approved and ordered June 6, 2008.
\(^{56}\) Refer to the Natsource report entitled “Addendum to Section 2(b) of Natsource’s ‘2007 Greenhouse Gas
Offset Forecast Report for BC Hydro’ dated December 1, 2007”, attached as Appendix G2.
the source of GHG emissions, provide for a regulation that exempts from the payment of
the tax, or that refunds of all or part of the tax paid, subject to compliance obligations
under the Carbon Tax Act and the new offset requirements for electricity generation
under the Emissions Standards Act. Regulations prescribing the specific requirements of
the Carbon Tax Act have not yet been introduced, and therefore BC Hydro has assumed
in the 2008 LTAP analysis that it will continue to pay the carbon tax for all fossil fuel used
for the generation of electricity at the three thermal generating facilities owned by
BC Hydro – Burrard, the 46 MW Prince Rupert Generating Station and the 47 MW FNG
and would pay the tax for any new carbon fuel based resource.

As described in Part II of the Natsource GHG price forecast report, a key question
influencing the GHG price in B.C. is the extent to which the Province’s forthcoming climate
change legislative and regulatory program will be harmonized with the Canadian Federal
Government’s GHG policies and Regulatory Framework. Under section 10 of CEPA, when
an instrument already exists in another jurisdiction (provincial/territorial) that achieves the
same environmental outcome as a CEPA regulation, the provincial or territorial instruments
apply instead of the CEPA regulation.57 For this to occur, the Province/Territory enters into
an equivalency agreement with the Government of Canada. The extent to which B.C.
entities will be able to participate in Federal compliance mechanisms such as the
Technology Fund and Federal offset system is unknown at this time, and may be dependent
on Federal actions in relation to U.S. regulatory developments. B.C. could decide to
maintain its participation in the WCI program and to meet its target independently, even after
a Federal program has commenced.

4.2.2.3  U.S. – Federal Government and State Initiatives

The evolving interrelationship between the GHG policies of Canada and the U.S. at the
Federal level is expected to significantly influence GHG prices faced by utilities in B.C.
Several pieces of legislation have been introduced in the 110th U.S. Congress that would
require mandatory GHG reductions and that would also establish an emissions trading
program. These proposals include:

57 For more information concerning Equivalency Agreements under the CEPA, refer to:
• Senator McCain’s and Senator Lieberman’s *Climate Stewardship and Innovation Act* (S. 280);

• Senator Lieberman’s and Senator Warner’s *America’s Climate Security Act* (S. 2191);

• Senator Sanders’ and Senator Boxer’s *Global Warming Pollution Reduction Act*; and

• Senator Bingaman’s and Senator Specter’s *Low Carbon Economy Act* (S. 1766) among several others.

The Natsource GHG price forecast report at Appendix G1 provides a detailed review of recent U.S. Federal legislative direction and new proposals currently under consideration by the U.S. Senate and House of Representatives.

At the time of writing the Natsource price forecast report, the impact of S. 280 on GHG prices had been modelled by a number of organizations, and formed the underpinning of the price forecast. S. 280 sets moderately stringent targets of approximately 17 per cent above 1990 levels for electric power generation and other covered sectors between 2012 and 2019; approximately equal to 1990 levels between 2020-2029; and approximately 22 per cent below 1990 levels between 2030-2049. By 2050, the cap is set approximately 60 per cent below 1990 levels. More recently, S. 2191, introduced in October 2007, has received considerable attention. S. 2191 is a somewhat more stringent Bill than S.280, setting a cap of approximately 13 per cent above 1990 levels by 2012 and 3 per cent below 1990 levels by 2020 for electric power generation and other covered sectors. The cap drops to 24 per cent below 1990 by 2030 and 45 per cent below 1990 by 2040. Given the timing of the U.S. Federal election, it is not clear which Bill will be signed into law before 2009-2010.

Several WECC states have either adopted generation GHG emission performance standards and/or GHG emission mitigation requirements. For example, California and Washington State have established GHG emission performance standards that prohibit load serving entities from entering into long-term financial commitments unless base load generation complies with a GHG emission performance standard not to exceed the rate of

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58 California Senate Bill (SB) 1368.
59 Washington State SB 6001.
emissions of a CCGT. Refer to Part II of the Natsource GHG price forecast report for further
details with respect to California, Washington State and other WECC states.

4.2.3 GHG Price Forecast

The starting point in quantitatively evaluating GHG risk is to develop specific assumptions
about GHG legislation that could plausibly be implemented over the lifetime of the resource
investments being considered. Despite the high level of activity in policy and regulatory
development related to GHGs, the specific form, and in some cases the timing, of many of
these developments is highly uncertain. Consequently, the potential implications for electric
resource economics and utility investment decisions is also highly uncertain. In
consideration of this uncertainty and to provide more reliable data for its analysis, BC Hydro
adopted a policy scenario approach to assess the impact of GHG regulation and GHG offset
price variability.

BC Hydro's GHG price forecast considers two key drivers influencing GHG price, the
stringency of regulatory policy (targets) and the flexibility of compliance mechanisms
(supply/availability). Three scenarios were created by Natsource to describe the range of
potential GHG policies for the years 2007-2050. These scenarios were not intended to
predict specific outcomes, but rather, to provide reasonable upper and lower bounds for the
GHG price forecast. Natsource applied its experience and knowledge of GHG policy and
markets to assign a best estimate probability of occurrence for each of the three scenarios.
In addition, given the recent legislative actions and announcements by the Province of B.C.,
two sensitivity cases were described for the near term 2007-2020, when B.C. may decide to
pursue emission reduction programs, either on its own, or as part of a regional group such
as WCI or WECC.

The various scenarios and sensitivity cases developed and applied by Natsource are
described briefly below. In addition, Natsource estimated the probability for each of the three
main scenarios and those probability assessments are included with the summaries that
follow. Detailed descriptions of the scenarios are found in the Natsource GHG Forecast
report at Appendix G1 and the rationale for the probability estimates is found in the
Natsource report entitled “Probabilities for scenarios in Natsource’s “2007 Greenhouse Gas
Offset Forecast Report for BC Hydro”, attached as Appendix G3.
The price scenarios are:

- "Price Cap" Scenario: Canada and the U.S. are outside of an international agreement and implement less ambitious GHG regulatory policies, including capped prices on GHG emissions, such as the Technology Fund of the current Regulatory Framework in Canada and less-stringent legislative proposals in the U.S., such as S. 1766’s proposed price ceiling. The “Price Cap” scenario was considered least likely (15 per cent probability), since price caps were considered less likely to be acceptable because they could jeopardize the achievement of an emissions cap;

- "Linked Markets" Scenario: Canada and the U.S. establish more ambitious targets and link trading programs after 2015. Both countries join an international framework by 2020, with limited constraints on domestic and international offsets. The Linked Markets scenario was considered most likely (60 per cent probability); and

- "Made in North America-Aggressive Targets" Scenario: Canada and the U.S. establish more aggressive targets and link trading in 2012, but do not join an international regime. International offsets (outside of North America) are not allowed. The “Made in North America” scenario was considered second most likely (25 per cent probability),

The sensitivities affecting the B.C. region are:

- "WCI/WECC" sensitivity analysis: B.C. will meet its stated reduction targets as a participant in a WCI regional trading program starting in 2012. Eligible offsets would be created within the WCI/WECC region. The WCI/WECC sensitivity case was considered most likely for estimating GHG price in B.C. for the near-term 2012 – 2015; and

- "B.C. only" sensitivity analysis: B.C. will meet its stated reduction targets with legally binding hard caps, without using offsets or compliance instruments from outside the province. This B.C. only case was not considered likely, because the current activity of the WCI in developing a cap-and-trade system was considered more likely to influence GHG price in the near term, but is included for completeness to determine a potential high bound in B.C.

Table 4-1 summarizes the $/tonne GHG offset costs for the three scenarios. Table 4-2 summarizes the two nearer term price sensitivities that may impact B.C.
### Table 4-1  Price Estimates for Planning Scenarios (CDN $ 2008)

<table>
<thead>
<tr>
<th>Year</th>
<th>2010</th>
<th>2012</th>
<th>2015</th>
<th>2020</th>
<th>2030</th>
<th>2040</th>
<th>2050</th>
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<tr>
<td>Price Cap scenario ($)</td>
<td>14</td>
<td>14</td>
<td>18</td>
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<td>18</td>
<td>18</td>
<td>18</td>
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<tr>
<td>Linked Markets Scenario</td>
<td>Price Range ($)</td>
<td>n/a</td>
<td>Canada: 14</td>
<td>Canada: 15 - 25</td>
<td>US: 12-18</td>
<td>24 - 54</td>
<td>39 - 59</td>
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<tr>
<td>Mid Point ($)</td>
<td>Canada 14</td>
<td>US 15</td>
<td>20</td>
<td>39</td>
<td>49</td>
<td>80</td>
<td></td>
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<tr>
<td>Made in North America Aggressive Targets Scenario</td>
<td>Price Range ($)</td>
<td>n/a</td>
<td>16 - 24</td>
<td>24 - 47</td>
<td>35 - 57</td>
<td>65 - 84</td>
<td>112 - 124</td>
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<tr>
<td>Mid Point ($)</td>
<td>20</td>
<td>36</td>
<td>46</td>
<td>75</td>
<td>118</td>
<td>177</td>
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### Table 4-2  Price Estimates for Sensitivity Cases for B.C. Compliance Instruments (CDN $2008)

<table>
<thead>
<tr>
<th>Year</th>
<th>2012</th>
<th>2015</th>
<th>2020</th>
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<tbody>
<tr>
<td>WECC Compliance Instruments applied to price cap scenario</td>
<td>Range ($)</td>
<td>9 - 14</td>
<td>16 - 46</td>
</tr>
<tr>
<td>Mid point ($)</td>
<td>12</td>
<td>31</td>
<td>78</td>
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<tr>
<td>BC Compliance Instruments Only applied to all scenarios</td>
<td>Range ($)</td>
<td>78 - 116</td>
<td>140 - 258</td>
</tr>
<tr>
<td>Mid point ($)</td>
<td>97</td>
<td>199</td>
<td>&gt;291</td>
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</table>
4.2.3.1 **Economic modeling activity subsequent to the Natsource report**

These price forecasts are based on existing economic modeling available at the time the Natsource GHG price forecast report was written in December 2007.

Price estimates for S. 2191, the most stringent of the U.S. Bills examined by Natsource, were not available in December 2007, although subsequently several organizations have conducted modeling of the Bill. As identified earlier, a high degree of uncertainty exists surrounding the level of targets that ultimately will be adopted in U.S. legislation. The U.S. Senate has not yet debated S. 2191. The debate is likely to address targets and economic costs and will provide some further indication of emerging views on what level of target is considered both necessary and economically acceptable. These views will continue to evolve in 2008, and following the election of a new President and Congress in November. In view of the still preliminary state of discussion on climate proposals in the Congress, it is not clear that the targets in S. 2191 are more representative of the targets that will ultimately be adopted than those in S. 280. If the targets in S. 2191 are more representative, then prices under a U.S. program likely would be in the upper ranges of the Linked Market and the Made in North America Aggressive scenarios, or indeed higher than those scenarios. Given the uncertainty over which U.S. GHG Bill will be enacted, Natsource has not recommended changes to its GHG price forecast report.

Price estimates for the least stringent of the proposals examined by the Natsource GHG price forecast report (S. 1766) were not available at the time the report was prepared. These estimates relate only to prices in the U.S. under S. 1766, and do not directly impact the report’s estimates for the Price Cap scenario. The Price Cap scenario price estimates in the report are prices for regulated entities in Canada, and the Price Cap scenario assumes that the U.S. and Canada do not link their trading programs.

In Canada, the Federal Government released its economic analysis and modeling of Canada’s federal plan on March 10, 2008. The modeling results of this analysis, which were not available at the time the scenarios in the Natsource GHG price forecast report were developed, suggest that Canada’s current policy approach, including an intensity

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target with a Technology Fund compliance option, would lead to prices in Canada that are higher than those considered in the Price Cap scenario (which assumes Canada’s current approach extends indefinitely), and to higher prices in Canada in the Linked Markets scenario (which assumes Canada’s current approach extends to 2015). The analysis estimates the price of GHG emission permits under the March 2008 Regulatory Framework will be approximately $25/tonne in 2010-2012, rising to $65/tonne in 2018-2020. The Technology Fund contributions ($15/tonne in 2010-2012, $20 in 2013 and escalating at the rate of nominal Gross Domestic Product thereafter) moderate prices at the beginning of the program but play a limited role after 2014 given the limited access to the Technology Fund. In 2018-2020 contributions are exhausted and prices increase to $65. These prices are somewhat higher than in the Linked Markets scenario through 2015 and significantly higher thereafter. This underscores the uncertainty in forecasting GHG prices, and suggests that prices may be trending toward higher levels, although the absence of competing analyses, and the absence of detailed assumptions in the Federal Government’s economic analysis, raise questions as to whether the Federal Government’s relatively high price estimates are representative.\textsuperscript{61}

4.2.4 Use of GHG Price Forecast in 2008 LTAP Analysis

4.2.4.1 Direct Impact in the Portfolio Analysis

Both the B.C. carbon tax and the Natsource GHG price forecast have been included in the 2008 LTAP Chapter 5 portfolio analysis. The B.C. carbon tax is included as part of the fuel cost of any natural gas-fired generation located in B.C. The tax is assumed to be that identified in the \textit{Carbon Tax Act}, with the ultimate tax level in 2012 being extended through the remainder of the planning horizon.

BC Hydro incorporated Natsource’s GHG price forecast into its portfolio analysis based on the Mid Point values presented in Table 4-1 and Table 4-2 as trended in Figure 4-1. The

\textsuperscript{61} Environment Canada stated the following with respect to the modelling: “Analysis of the economic impact of the Regulatory Framework is complex. The results presented here are based on an economic modeling structure that has a longstanding track record in Canada and the United States with respect to impact analysis of climate change measures. This gives us high confidence in our conclusions, but it must be recognized that no single economic model can claim absolute certainty in its results. As with complex policy analysis, application of alternate modelling approaches to generate a range of estimates is desirable. To this end, Environment Canada is working with other government departments and external experts to support Canada’s environmental agenda on the basis of a robust and comprehensive analytical capacity.” \textit{Supra}, note 16.
Figure presents both the broader planning scenarios as well as the scenarios that would relate to B.C. until the GHG offset markets link. The methodology of how the GHG price forecast is incorporated is described in Chapter 5.

4.2.4.2 Accounting for Indirect Impacts of GHG Regulations

In addition to the direct impacts identified above, there is an indirect impact of GHG regulations for utilities’ resource planning environment through the scenario forecasts of natural gas and electricity market prices. This impact is described in the following sections on natural gas and electricity markets that follow.
4.3 Natural Gas Price Forecast

4.3.1 Global Energy Forecasts

For the 2008 LTAP, BC Hydro retained Global Energy for fundamental research and natural gas price forecasts. This is an extension of the types of services that Global Energy has provided in the past; Global Energy has provided BC Hydro with market forecast services for several years and BC Hydro has used a Global Energy electricity market simulation model to develop its recent electricity price forecasts.62

The natural gas price scenarios developed for BC Hydro by Global Energy are derived from three internally consistent, fundamentals-based scenarios of future market conditions that Global Energy developed for the CEC as part of the CEC’s IEPR process. The three natural gas price forecasts – referred to as 1B (Base), 2 (High) and 5BPlus (Low) – were selected because they cover a wide range of possible natural gas prices.

At a macro level, the natural gas prices identified in each of the scenarios are impacted by the underlying assumptions of North American natural gas supply and demand. Within the Western Canadian and U.S. region, the natural gas demand is impacted by the forecast of electricity demand and the relative competitiveness of natural gas-fired generation. The Global Energy natural gas forecast takes into account the impact of electricity demand in the region, various scenarios of penetration of DSM and renewable generation in the region.

BC Hydro requested that Global Energy provide its expert view as to the relative probabilities of the three scenarios. Following a structured review, Global Energy assigned probabilities to its three natural gas forecasts as follows: 1B (Base) – 44 per cent; 2 (High) – 53 per cent; and 5BPlus (Low) – 3 per cent.

The details regarding the underlying conditions (global and within the western region) that resulted in the three gas price scenarios, the analysis and review that went into creating the scenarios, and the analysis that went into assessing the relative probabilities of the three scenarios are provided in the Global Energy report contained in Appendix I.

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62 BC Hydro is a licensee of the Global Energy Decisions MARKETSYM simulation software. BC Hydro has used the software to produce forecasts for more than ten years.
Figure 4-2 presents the three scenarios of natural gas prices for the Sumas Hub\(^{63}\) in Canadian dollars.

### Figure 4-2 Natural Gas Price Scenarios at Sumas Hub by Calendar Year

- **Low Forecast**
- **Mid Forecast**
- **High Forecast**

#### 4.3.2 EIA Annual Energy Outlook Natural Gas Forecast

For the 2006 IEP/LTAP, BC Hydro used the EIA’s 2005 Reference Case for its medium scenario. The 2008 LTAP does not rely on the EIA’s Reference Case. Over the last 10 years, EIA’s Annual Energy Outlook (AEO) forecasts have been consistently low. This is shown in Figure 4-3, which compares past EIA AEO forecasts to realized spot market prices. EIA AEO forecasts have increased over time but for the last 10 years have underestimated actuals. New York Mercantile Exchange (NYMEX) futures are much higher.

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\(^{63}\) Sumas Hub is a natural gas trading hub located near the Canada/U.S. border.
than the EIA AEO forecasts. For example, current market forwards at Henry Hub\textsuperscript{64} are over $11/Million British Thermal Units (MMBtu) ($USD) for each of the next 12 months.\textsuperscript{65}

**Figure 4-3** Comparison of EIA Natural Gas Forecast

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**4.3.3 Use of Natural Gas Price Forecast in 2008 LTAP Analysis**

The three Global Energy natural gas price forecasts were used as key inputs to develop three electricity price forecasts, described below. In addition, the use of these three scenarios in the 2008 LTAP portfolio analysis is described in Chapter 5. The three natural gas price forecasts, and the three GHG price forecasts, combine two of the risk factors that concern BC Hydro most: fuel price and GHG risk. Both factors primarily affect natural gas-fired generation facilities. Use of the scenarios in the Fort Nelson Resource Plan analysis is described in Appendix N1.

\textsuperscript{64} Henry Hub is the pricing point for natural gas contracts traded on the New York Mercantile Exchange (Nymex).

\textsuperscript{65} Natural Gas Forwards from Nymex’s April 29\textsuperscript{th} 2008 trading session [www.nymex.com](http://www.nymex.com).
4.4 Electricity Price Forecast

4.4.1 General

WECC’s electricity and natural gas markets have become closely inter-related since natural gas has become the predominant fuel for new electricity generation. The inter-related nature of the electricity and natural gas markets means that market prices for electricity are closely tied to the market prices for natural gas. This is due to natural gas-fired generation’s operational flexibility and relatively high variable operating costs, which typically place it last in the order of generation resources to be dispatched. As such, natural gas-fired generation is the marginal market resource and high gas prices are likely to drive high electricity market prices.

Electricity prices are modelled under a computer simulation of the hourly supply-demand balance for the WECC regional market, which include the Western U.S. states, B.C. and Alberta. The dispatch cost of the marginal resource at the point where supply and demand are in equilibrium determines the market price for that hour. Monthly and yearly average prices are obtained by aggregating the computed hourly prices. The electricity and gas prices are calculated for the next 20 years.

The electricity price forecasts were developed in a two-stage process. In the first stage, Global Energy developed the database of scenarios of loads and resources in the western region. This forecast expressly includes the underlying assumptions for DSM, renewable resources and conventional resources in the region by sub region (refer to Figure 4-4) and by scenario.
The second stage was completed by BC Hydro and starts from the Global Energy database and the three natural gas scenarios. BC Hydro made certain modifications to the database with respect to the B.C. area, including additional precision with respect to the BC Hydro resources.\(^{66}\)

### 4.4.2 Incorporation of GHG Price Forecast

In the second stage of developing the 2008 Electricity Price Forecast, BC Hydro simulated the impact of GHG offset costs on the region. As part of this exercise, Natsource was asked to derive thermal generator “performance standards”. The importance of the thermal generator performance standards is that GHG costs are only incurred for GHG emissions above the particular performance standard. Natsource reviewed the GHG legislation and policy developments in the Canadian provinces and U.S. states that make up the WECC. Natsource then converted the various legislative requirements into GHG intensity targets.

Natsource and BC Hydro found the following:

\(^{66}\) It is a standard practice to modify the base Global Energy database with specific information BC Hydro has with respect to the current and forecast local conditions.
• B.C. requires all new thermal generators to have zero net GHG emissions (the Emissions Standards Act and Policy Action No. 18 of the 2007 Energy Plan). This results in the B.C. performance standard being set at zero;

• California, Washington State and Oregon require thermal plants to offset to the equivalent of a CCGT. This results in the California, Washington State and Oregon performance standards being set at 360 tonnes of CO$_2$e/GWh. The 360 tonnes of CO$_2$e/GWh is the GHG intensity of a new, efficient CCGT. This means that generally speaking new CCGTs are exempt from GHG offset costs in all three states. Coal-fired generators and lower efficiency gas-fired generators would have to offset to the level of a CCGT. Washington State mandated a review of its performance standard every 5 years. California and Oregon have to date been silent on whether and when their respective performance standards will be updated; however, California’s performance standard is an interim measure until the WCI GHG cap-and-trade system is in place; and

• In the rest of WECC (Alberta, Arizona, New Mexico, Montana, Utah, Colorado, Nevada, Idaho, Wyoming), some of these jurisdictions do not yet have legislation addressing GHG emission targets, while others have only broad state-wide targets. This results in the rest of WECC performance standard being set at 600 tonnes of CO$_2$e/GWh. The 600 tonnes of CO$_2$e/GWh is the mid point of the range of 500-700 tonnes of CO$_2$e/GWh developed by Natsource based on the GHG emission intensity of higher emissions gas-fired generators or fairly clean coal-fired generators. Generally coal-fired generators have GHG emissions intensities of between 495 to over 1,000 tonnes of CO$_2$e/GWh.

Including the GHG offset cost assumptions into the 2008 Electricity Price Forecast resulted in an increase of between $2.00/MWh and $4.00/MWh (2006 dollars) in the electricity prices across the region. Figure 4-5 presents the impact of the GHG offset cost assumption as measured at Mid C based on Natsource’s linked market GHG scenario.
1. **4.4.3 2008 Electricity Price Forecast**

The forecast for Mid-C in Canadian dollars is provided in Figure 4-6.

2. The forecast for Mid-C in Canadian dollars is provided in Figure 4-6.
4.4.4 Use of Electricity Price Forecast in 2008 LTAP Analysis

The use of these three scenarios in the 2008 LTAP portfolio analysis is described in Chapter 5. Use of the scenarios in the Fort Nelson resource plan analysis is described in Appendix N1. The 2008 Electricity Price Forecast is used to determine compensation for non-firm energy produced by successful bidders in the Clean Power Call. The 2008 Electricity Price Forecast will also be used to determine the relative values of monthly on-peak and off-peak energy produced by successfully bidders in the Clean Power Call. Refer to section 6.2.6 for details.

4.5 Market Assessment for Clean or Renewable Electricity

One of the more significant changes in U.S. markets since the 2006 IEP/LTAP is the increasing number of U.S. states that have passed RPS legislation. As of May 1, 2008, 25 U.S. states and the District of Columbia, including eight WECC states, have adopted mandatory RPS requirements. A mandatory RPS obligates utilities to include in their resource portfolios a certain amount of electricity from renewable energy resources, such as wind and small hydro (generally less than 30 MW and with no storage).

RPS requirements vary considerably with respect to resource eligibility, whether they allow unbundled RECs, and arrangements for enforcement and penalties. The use of unbundled RECs separates the attributes of renewable electricity – such as emissions from a generator - from the electricity itself, creating an entirely separate market for the renewable attribute alone, which is unencumbered by the physical constraints of the transmission grid.

4.5.1 Global Energy Analysis

BC Hydro retained Global Energy to:

- Obtain an indication of the possibility of B.C.-based supply being able to access the WECC market; and

67 Initially, all RECs are “bundled” together with their associated electricity that is produced at the renewable electricity generation facility. RECs can be conveyed with the electricity unless they are “unbundled” from the electricity and recorded in a certificate that may be traded separately from the electricity itself: see section 2.1 of Global Energy’s report entitled “Renewable Energy Credit – Markey Analysis of Potential Renewable Energy Sale in WECC”, attached as Appendix H.
1. Obtain an objective view as to what the value of RECs would be in the future.

2. Global Energy concludes that most WECC state RPS legislation allows out-of-country renewable electricity products, with some states being more restrictive than others. Refer to Table 4-3, which summarizes Global Energy’s findings. Refer to Appendix H for further details.

Table 4-3  RPS Eligibility for Wind and Hydroelectric resources

<table>
<thead>
<tr>
<th>State</th>
<th>Wind</th>
<th>Hydro</th>
<th>Unbundled RECs allowed?</th>
<th>Geographic restrictions</th>
</tr>
</thead>
<tbody>
<tr>
<td>Arizona</td>
<td>Yes</td>
<td></td>
<td>Hydroelectricity from facilities that became operational after January 1, 1997, as well as hydro used to firm intermittent renewables, and incremental generation from upgrades from facilities that became operational before January 1, 1997 is eligible.</td>
<td>Arizona allows the use of unbundled, tradable RECs.</td>
</tr>
<tr>
<td>California</td>
<td>Yes</td>
<td>Facilities with capacity below 30 MW are eligible. Facilities outside of California must not require new water permits or licenses from any government bodies.</td>
<td>California Public Owned Utilities can use unbundled RECs if they so choose. California Investor Owned Utilities require California Public Utilities Commission (CPUC) approval before doing so. The CPUC is likely to approve the use unbundled RECs soon.</td>
<td>RECs must be from facilities connected to WECC that became operational on or after January 1, 2005, or from incremental generation from a project expansion after January 1, 2005. Facilities outside the US must operate in a manner that is protective of the environment, similar to facilities located in California.</td>
</tr>
<tr>
<td>Colorado</td>
<td>Yes</td>
<td>Yes</td>
<td>Colorado House Bill 07-1281 allows tradable RECs (which are the equivalent of unbundled RECs).</td>
<td>No restrictions.</td>
</tr>
<tr>
<td>State</td>
<td>Wind</td>
<td>Hydro</td>
<td>Unbundled RECs allowed?</td>
<td>Geographic restrictions</td>
</tr>
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<tr>
<td>Montana</td>
<td>Yes</td>
<td>Hydroelectricity from facilities with a capacity of 10 MW or less are eligible.</td>
<td>Yes</td>
<td>RECs from facilities in other states that became operational after January 1, 2005, are eligible.</td>
</tr>
<tr>
<td>Nevada</td>
<td>Yes</td>
<td>Certain hydropower is eligible.</td>
<td></td>
<td>No restrictions.</td>
</tr>
<tr>
<td>New Mexico</td>
<td>Yes</td>
<td>Hydroelectricity from facilities that became operational after July 1, 2007 are eligible.</td>
<td>Yes</td>
<td>RECs must be from facilities connected to WECC.</td>
</tr>
<tr>
<td>Oregon</td>
<td>Yes</td>
<td>Hydroelectricity from facilities that became operational on or after 1995 are eligible.</td>
<td>Yes</td>
<td>Unbundled RECs must be from with in the WECC territory, or from an area deemed “environmentally preferable” by the Bonneville Power Administration. Bundled RECs must be from the U.S. portion of the WECC territory.</td>
</tr>
</tbody>
</table>

1. Global Energy further confirms that U.S. state RPS requirements are likely to continue if the WCI or some other GHG cap-and-trade system is brought into effect. Global Energy’s analysis confirms BC Hydro’s view that title to “Environmental Attributes” resulting from the Clean Power Call must be transferred to BC Hydro so that the value from any sales of Environmental Attributes flows back to BC Hydro’s customers. Refer to section 6.2.6.
Table 4-4 shows Global Energy’s expected range of REC prices.

<table>
<thead>
<tr>
<th>Year</th>
<th>2010</th>
<th>2015</th>
<th>2020</th>
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<tr>
<td>High</td>
<td>57</td>
<td>59</td>
<td>62</td>
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<tr>
<td>Low</td>
<td>11</td>
<td>14</td>
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4.5.2 Use of Global Energy Analysis in 2008 LTAP Analysis

As was the case in the 2006 IEP/LTAP, sales and purchases of electricity are modelled in the 2008 LTAP portfolio analysis. The sales and purchases assumed to be made in the analysis are based on pricing at two external trading hubs – the Mid-C and the Alberta AESO Hubs. In each case, wheeling and losses are captured to the respective hub. The value of these sales and purchases are for the base electricity product (the electrons), without any representation of the incremental value that may be derived from the sale or purchase of RECs or any other form of clean or renewable attribute.

BC Hydro’s portfolio analysis in Chapter 5 includes the estimated incremental revenue that would result from the sale of the clean or renewable electricity from the BC Hydro system. The incremental price forecast that was used for estimating the revenues is provided in Figure 4-7. The BC Hydro scenarios were selected in the lower half of the Global Energy forecast reflecting the uncertainty of the ultimate price threshold that may result in each receiving jurisdiction before the local utilities are allowed to reduce their RPS obligations because of rate impacts.
4.5.3 Transmission

As part of its long portfolio analysis in Chapter 5, BC Hydro undertook an analysis of transmission access.

Current Interconnection Ratings

B.C. is interconnected with both the Alberta and the U.S. markets. The interconnection going into Alberta is typically limited to between 400-600 MW, although the rating can be increased on a short-term basis by actions within Alberta. The interconnection going into the U.S. has a concurrent limit of 3150 MW across the two points of interconnection. However, the actual available North-to-South scheduling capability of the U.S. intertie during Heavy Load Hours (HLH) is often substantially less (1500-2500 MW range) than the 3150 MW rating.
As set out in the long portfolio analysis found in Chapter 5, under SD 10 planning criteria, BC Hydro would under normal water conditions typically have 6000-8000 GWh/yr of energy that would be surplus to its load requirements. This surplus could exceed, but with a decreasing probability of occurrence, 10,000 GWh in a year. Even at this level of energy surplus the existing transmission system is, with appropriate planning, physically capable of moving 10,000 GWh out of B.C. in addition to meeting load. To move this surplus energy however, could have a significant economic opportunity cost because transmission and generation limits would require the surplus energy to be sold into time periods that typically have less economic value (e.g., Light Load Hours (LLH) and spring/late fall HLH) than other times of the year.

Under this circumstance, consideration could be given to expanding the capability of the interconnection. The direct benefit that could be obtained from increasing the transmission limits would depend upon the relationship between:

- the cost of that transmission upgrade;
- the limits on generation and storage capability; and
- the incremental market value that could be obtained by selling the energy into higher value time periods.

There could also be indirect benefits associated with increased transmission capability that would have to be quantified. A key consideration is that under the current BCTC tariff, BC Hydro will backstop the cost of expansion via its NITS but to guarantee that it will receive the associated benefits BC Hydro would also need to secure the capacity rights via long term firm Point-to-Point contracts.

**Western Renewable Energy Zone**

A number of U.S. states, including Arizona, California, Colorado, Nevada, New Mexico, Utah and Wyoming are working to identify renewable resources in their states and to determine the transmission needed to move generation to load centers. However, concerns over restricting renewable procurement and transmission development to in-state and the resulting higher costs to consumers has led the U.S. Western Governors’ Association and other stakeholders to support the Western Renewable Energy Zone (WREZ) initiative to
develop a consensus proposal among the WECC jurisdictions on how best to develop and deliver energy from renewable resource areas throughout the WECC region, including B.C., to load centers. Specifically, the WREZ initiative is to:

- Identify all commercial renewable resource potential in the WECC, aggregate the best potential into Renewable Energy Zones (REZ), and identify transmission costs to deliver resources from each REZ to specified load centers; and

- Develop conceptual transmission plans to deliver energy from the highest ranking REZs to identified load centers.

BC Hydro will continue to monitor the WREZ.
RISK FRAMEWORK AND PORTFOLIO ANALYSIS
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5.1 Introduction

The goal of the 2008 LTAP is to identify, within the context of the 2007 Energy Plan and related legislation, including special directions, a cost-effective\textsuperscript{68} combination of existing and new supply side and demand side resources for its customers.

The key issues and options that BC Hydro considered in the 2008 LTAP are as follows:

- The future role of Burrard;
- Amount of DSM;
- Timing and nature of Calls for Energy;
- Need and timing for further Columbia River capacity units; and
- The value of maintaining Site C as an option.

The 2008 LTAP sets out a framework to assess the load requirements, the contribution of the existing system and identifies targeted volumes for each major resource option. Chapter 5 provides the analysis of the key issues and options while Chapter 6 provides the recommended actions that BC Hydro is planning to undertake.

BC Hydro continues to face considerable uncertainty in its planning environment. Uncertainty is analyzed in three ways in the 2008 LTAP:

- Stochastically - For quantifiable uncertainties for particular variables. From their historic value, parameters can be numerically generated to produce a known statistical process that represents their variability. An example is load uncertainty;
- Scenario Analysis - Scenario uncertainties are also parameter driven; however, the parameter variability cannot be reasonably represented by a known statistical process. Instead, a fundamental change or structural shift is made to the expected value of some parameter. In the case of changing scenario uncertainties, the time evolution of critical inputs, e.g., natural gas and electricity prices, takes a distinctly different path rather than fluctuating around an expected value. This uncertainty category is intended to embrace abrupt changes in the uncertainty factors such as the introduction of high GHG

\textsuperscript{68} The term "cost-effective" is defined in section 1.2.4.
allowances charges. Possible future outcomes or scenarios of these occurrence are
created; and

• Qualitative Assessment – A number of uncertainties, for example the uncertainty of
permitting a rebuilding of Burrard, do not lend themselves to either stochastic or scenario
analysis. For these uncertainties, BC Hydro has either retained experts to provide advice
or relied upon professional judgement.

Scenario analysis and qualitative assessment are referred to as “subjective assessments”.
To provide a clear understanding of the uncertainties and risks and how they are combined
in the analysis, BC Hydro is using a risk framework as shown in section 5.2.

The Risk Framework has four key elements:

• Characterization of uncertainty using either stochastic modelling or scenario
  assessments;

• Combining uncertainty characterizations with portfolio analysis to assess the potential
  impacts of options over the 20 year planning horizon;

• Providing a qualitative assessment of other factors and considerations that have not been
  included in the quantitative portfolio analysis; and

• Providing mitigation for risks that need to be managed.

The remainder of the Chapter 5 is structured as follows:

• Section 5.2 – Risk Framework – the framework through which key uncertainties were
  addressed in the LTAP using:
    ‣ Probability Assessments (section 5.2.2) – which focus on the key uncertainties that
      were quantified for the LTAP; and
    ‣ Probability Trees (section 5.2.3) – which show how these quantified uncertainties were
      combined into a small number of discrete scenarios to help focus the portfolio
      analysis.

• Section 5.3 – Portfolio Analysis – provides an update on key issues that have changed in
  the portfolio modelling process since the 2006 IEP/ LTAP and an overview of the
  portfolios modelled in the 2008 LTAP analysis;
The remaining sections show the analysis, building on the probability assessments from section 5.2 and applying quantitative and qualitative analysis to the following key issues:

- Section 5.4 – Burrard
- Section 5.5 – DSM
- Section 5.6 – Acquisition (Calls for Power)
- Section 5.7 – Mica Unit 5 and Mica Unit 6 and Revelstoke Unit 6
- Section 5.8 – Site C
- Section 5.9 – Additional Analysis Considerations
  - Section 5.9.1 - Impacts of Exchange Rates
  - Section 5.9.2 – Impact of Discount Rate
  - Section 5.9.3 – Long Portfolio Impacts

### 5.2 Risk Framework

The Risk Framework is the general approach by which BC Hydro incorporated uncertainty into the LTAP analysis.

#### 5.2.1 Risk Framework Definitions and Key Uncertainties and Risks

To provide a clear discussion of the uncertainties and risks that BC Hydro is facing and managing, the following definitions are provided:

- **Key Uncertainties**: Are variables with unknown outcomes and likelihoods that were expected to affect key decisions in the 2008 LTAP; and
- **Risks**: Are uncertainties which may have outcomes that result in adverse impacts on BC Hydro and its customers.

Within the Risk Framework, different approaches were used to assess uncertainty and risk:

- **Stochastic modelling**: Variables that were modelled stochastically have a record of historic values that give a good basis on which to forecast future values; and
Subjective Assessment - Variables that did not have a good historical record on which to forecast future outcomes can be handled subjectively. Subjective assessments can either be qualitative or quantitative. Subjective assessment includes scenario analysis.

Key stochastic uncertainties and related risks include:

- Load growth and the risk that load growth exceeds or falls below expectations;
- Features of BC Hydro’s existing system and its operations, including inflow and water variability, and the risk of insufficient energy; and
- Natural gas and electricity spot market uncertainty and risks that prices vary from period to period.

Key uncertainties and related risks that were assessed on a subjective basis include:

- Natural gas and electricity market uncertainty and risks where price changes result from a fundamental change in the market such that prior historical observations are no longer reflective of future price potential (examples include the 2000/2001 price spikes and the impact of liquefied natural gas introduction into the markets);
- Current and future regulatory and public policy developments, such as GHG regulation, new air emission standards and related mitigation cost risks;
- IPP development including type of resource and location and the risk that the type and location of resources require significant capacity and transmission support;
- IPP attrition rates from Calls;
- DSM deliverability and risk that the response to DSM is less than planned or required;
- Transmission supply and the risk that this long lead time resource faces construction delays and permitting problems; and
- Burrard and the uncertainty around its technical ability and social license to deliver firm energy and capacity.

5.2.2 Quantifying Uncertainty

The 2008 LTAP addresses energy planning options in the face of numerous uncertainties. The challenge is to incorporate these unknowns (both the stochastic uncertainties and the...
subjectively assessed ones) into a framework of analysis. To the extent possible, BC Hydro has applied numerical probability assessments in an attempt to quantify “difficult to quantify” topics. For the variables that had a probability assessment undertaken, the approach:

- developed a discrete range of possible outcomes (e.g., High, Mid, and Low);
- used a structured, consistent method to attach a probability estimate to these discrete outcomes; and then
- combined the results using a probability tree.

The following sections describe the outcomes of the three aspects listed above. Appendix F14 looks at these steps in more detail, describing the steps taken and addressing best practices and theoretical concerns where pertinent.

Key uncertainties quantified

The following list depicts the uncertainties addressed through quantitative analysis:

- Net Demand - including DSM (performance uncertainty, note that DSM performance uncertainty is also addressed through qualitative assessment) and Load Forecast (forecast uncertainty); and
- Cost of Thermal Generation - including Gas and Electricity Price Forecast (forecast uncertainty) and GHG Offset Cost (forecast uncertainty).

Hydrology and spot market prices for gas and electricity are also key uncertainties for BC Hydro. These were incorporated into the planning criteria and portfolio modelling process rather than being incorporated explicitly into the quantitative portion of the Risk Framework.

Developing a Range of Discrete Outcomes

A key objective of the risk framework was to de-emphasize single point estimates for uncertain parameters and, instead, develop ranges of possible outcomes. For some elements, this meant developing distinct scenarios that covered off upper and lower bounds and a mid-case. This included the natural gas price forecasts, electricity price forecasts, and GHG offset costs. These discrete distributions could then be used in a probability tree (see section 5.2.3 for Probability Tree discussion). For the remainder of the issues considered,
including DSM savings and load growth, this meant taking continuous distributions and
simplifying them into three point distributions. This allowed the range of uncertainty and the
central tendency of the estimate to be captured while also allowing all issues to be built into
the probability tree.

*Attaching Probability Estimates to Discrete Outcomes*

For the key risks that had their uncertainty captured through stochastic modelling (including:
Load Forecast, DSM Savings, and IPP attrition), the information contained in their
continuous uncertainty distributions were used to put probabilities on the three discrete
levels of outcomes. Appendix F14 gives an explanation of these calculations and an
example.

Some of the remaining key uncertainties captured in the risk framework were estimates
derived from the creation of scenarios. Probabilities were assigned to these scenarios using
expert judgment. The details of how these probabilities are arrived at are case specific and
the general approach for eliciting probability judgments from experts is described in
Appendix F14 along with references to key considerations and best practices where
pertinent.

The remainder of section 5.2.2 will present the results of the probability assessments and
then section 5.2.3 will use these results in the development of a probability tree.

5.2.2.1 *Uncertainty Regarding Net Demand Forecasts*

Net demand is the level of demand after savings from DSM have been accounted for.
Forecasting net demand is one of the first steps in resource planning, but is subject to the
joint and distinct uncertainties of forecasting load growth and forecasting DSM savings.

Estimates of the range of outcomes around the forecast levels were developed for load
growth and DSM savings (see Appendix F14). These were combined to yield a range of
possible outcomes for net demand along with the associated relative likelihoods of seeing
these outcomes. This resulted in three scenarios of the change in net demand over time.
Table 5-1 shows a snapshot of these values in 2020, along with their associated
probabilities.
Table 5-1  Representing Uncertainty Regarding Net Demand

<table>
<thead>
<tr>
<th>Net Demand Scenarios</th>
<th>Low Net Demand</th>
<th>Mid Net Demand</th>
<th>High Net Demand</th>
</tr>
</thead>
<tbody>
<tr>
<td>Relative Likelihood</td>
<td>10 per cent</td>
<td>80 per cent</td>
<td>10 per cent</td>
</tr>
<tr>
<td>GWh (2020)</td>
<td>55,000</td>
<td>59,800</td>
<td>65,500</td>
</tr>
</tbody>
</table>

A more detailed description of the steps taken to assess these probabilities and combine them can be found in Appendix F14. For a given level of supply side resources, Table 5-1 also presents the identifiers that are used to describe the expected size of the gap between supply and demand over time. Further references to “the gap” are used to underscore this point throughout this and the following chapters.

5.2.2.2 Representing Uncertainty Regarding the Cost of Thermal Operations

The cost of thermal generation is a key input into energy planning. To capture the uncertainty around these costs, two key drivers were isolated for further analysis: natural gas price forecasts and GHG offset cost forecasts.

As outlined in section 4.3, three scenarios were created to capture the range of future natural gas prices, along with their relative likelihoods. Section 4.2.3 outlined three scenarios of future GHG offset costs, along with their associated probabilities. These scenarios were all combined to capture the various possible futures for the cost of thermal operations.

To simplify analyses while still capturing the full range of costs and a mid-point estimate, the uncertainty around thermal operations was reduced to three scenarios with their relative likelihoods. A more detailed discussion of this approach can be found in Appendix F14. The results are reported in Table 5-2.

Table 5-2  Cost of Thermal Operations (Three-point Distribution)

<table>
<thead>
<tr>
<th>Cost of Thermal Operations Scenarios</th>
<th>Low (Low Gas, Low GHG)</th>
<th>Mid (Mid Gas, Mid GHG)</th>
<th>High (High Gas, High GHG)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Relative Likelihood</td>
<td>1 per cent</td>
<td>66 per cent</td>
<td>33 per cent</td>
</tr>
</tbody>
</table>

Because of the nature of the underlying gas and GHG offset distributions, it was prudent for some parts of the analysis to pull apart the influence of the GHG offset costs and the natural gas prices.
gas prices. The results of this more detailed look at the possible future costs of thermal operations are displayed in Table 5-3.

Table 5-3 Cost of Thermal Operations (Five-point Distribution)

<table>
<thead>
<tr>
<th>Cost of Thermal Operations Scenarios</th>
<th>Relative Likelihood</th>
</tr>
</thead>
<tbody>
<tr>
<td>Low (Low Gas, Low GHG)</td>
<td>1 per cent</td>
</tr>
<tr>
<td>Mid (Mid Gas, Mid GHG)</td>
<td>31 per cent</td>
</tr>
<tr>
<td>Mid Gas, High GHG</td>
<td>13 per cent</td>
</tr>
<tr>
<td>High Gas, Mid GHG</td>
<td>39 per cent</td>
</tr>
<tr>
<td>High (High Gas, High GHG)</td>
<td>16 per cent</td>
</tr>
</tbody>
</table>

5.2.3 Probability Trees

The framework for assessing probabilities in this LTAP focussed on a few key uncertainties for quantitative analysis. These included:

- Net Demand - including DSM (performance uncertainty), Load Growth (forecast uncertainty); and
- Cost of Thermal Generation - including Electricity/Gas Price Forecast (forecast uncertainty) and GHG Offset Cost (forecast uncertainty).

The previous section described how these key uncertainties were characterized using discrete distributions and how probabilities were assigned to these distributions. This section will explain how these key uncertainties were integrated into the LTAP analysis using a probability tree.

A probability tree can be used to combine a number of different, discrete scenarios and their probabilities. A full description of probability trees, how they are constructed and how to interpret them, can be found in Appendix F14. Very briefly, tracing along the branch of a probability tree will give rise to a unique scenario. Multiplying the probabilities along the branches gives the relative likelihood of that scenario.

Drawing on Figure 5-1 for an example, one possible scenario is that the growth of Net Demand is small and the Cost of Thermal Generation is low. This traces out the upper branch of the tree from left to right. The resulting figure of 0.1 per cent shows that the likelihood of being in a low Net Demand low Thermal cost world is very small compared to the chances of being in the other scenarios.
This probability tree for the 2008 LTAP provided the key backdrop against which resource planning options and portfolios were compared. By providing a few discrete branches in this probability tree, this framework allowed specific portfolios to be created for each future scenario. For the questions of interest, analyses were carried out across all of these scenarios with the costs and relative likelihood of these being reported.

In some cases, the main focus of the analysis is with respect to the higher probability mid gap, with less need to look at the high or low gap. In these cases, a five branch probability tree that incorporates the five mid branches of the tree in Figure 5-1 is used. The relative likelihoods (in per cent) in this case are those provided in Table 5-3.

Where separating out the respective influences of natural gas and GHG prices in the future was not critical, a reduced form of this probability tree was used to manage modelling effort. This reduced tree is shown in Figure 5-2.
For the portfolio analysis, the 2008 LTAP was looking for robustness across these diverse scenarios in the following ways:

- The LTAP drew its base direction from looking at elements in the portfolio analysis that performed well across a wide variety of different scenarios, and in particular, those that performed well in the most likely scenarios;

- The LTAP looked to the more extreme scenarios to inform its CRPs. In particular, the probability tree depicted what circumstances these CRPs were designed for, when they might occur and their relative likelihood; and

- By testing policy options and portfolios across these scenarios, the LTAP probability assessment was able to portray cost and impacts of key resource choices in a variety of circumstances. The relative likelihoods then allowed the probability-weighted cost impacts of these key resource choices across the range of scenarios.
5.3 Portfolio Analysis

5.3.1 Portfolio Analysis Methodology

BC Hydro’s main method for analysing resource choices is through portfolio analysis. Portfolio analysis is a process of developing and evaluating resource portfolios, each consisting of a combination of supply side and demand side resources, which meet customers’ electricity needs. BC Hydro has maintained the same portfolio analysis process in the 2008 LTAP as was used in the 2006 IEP/LTAP. Resource options in the 2008 LTAP, demand and supply options are expressed in 2008 constant dollars and cost levelization is for the planning period of 2011 to 2027. In its 2006 IEP/LTAP Decision, the BCUC agreed “that a portfolio analysis is consistent with the Commission’s Guidelines”, “is a best practice for IEP or IRP analysis”, and “is useful to BC Hydro management, stakeholders, and the Commission in reviewing acquisition plans”.69

This section describes the key issues for portfolio modelling, the models used and modelling assumptions made in the portfolio analysis.

5.3.2 Portfolio Analysis Models

The 2006 IEP/LTAP utilized two internally developed models.70

- Multi-Attribute Portfolio Analysis (MAPA); and
- Hydrological system simulation model (HYSIM).

In the 2008 LTAP, in addition to MAPA and HYSIM, System Optimizer (SO) was employed to select resources in the various portfolios. SO is a product of Ventyx (formerly Global Energy, Henwood), the company that also provide the Market Analytics software used by BC Hydro to produce its market electricity price forecasts. SO is a deterministic tool that undertakes a linear optimisation analysis to select an optimal portfolio of resources for a given set of input parameters. SO runs a similar system production cost modelling as MAPA/HYSIM except that it models an average water year, where MAPA/HYSIM run through the 60 years of water records in modelling the large hydro system.

69 2006 IEP/LTAP Decision, pages 89 and 90.
70 2006 IEP/LTAP, Chapter 6.
SO has been used to select the resources that are included in a particular resource portfolio. These costs were then confirmed with MAPA/HYSIM to ensure the models produced similar results. SO has eliminated the need to manually select the resources for particular portfolios. For a more detailed description of SO and comparison of the modelling methods to those of MAPA and HYSIM, please see Appendix F.

5.3.3 Natural Gas Plant Modelling

Key aspects of modelling natural gas fired units in the portfolio modelling are the ability to dispatch these plants; the implications of the 2007 Energy Plan and associated regulations; and the evolving framework for GHG outside of B.C. The two key drivers for dispatching natural gas units are:

- Market heat rate relative to a B.C. based gas-fired unit heat rate (including GHG offsets and related taxes); and
- Meeting load requirements reliably.

As a result of Policy Actions No. 18 and 19 and the Emissions Standards Act, all natural gas fired generation will be required to offset 100 per cent of their GHG emissions (existing plants by 2016 and new natural gas plants immediately). In addition, as described in section 4.2.2.2, BC Hydro has assumed for purposes of the 2008 LTAP that all natural gas-fired generation will be required to pay the carbon tax on natural gas usage established in the 2008 Provincial Budget and by the Carbon Tax Act. In contrast, the current expectation is that thermal plants (both coal and natural gas) in other parts of the WECC will be required to offset GHGs to the level of GHG emission that an efficient CCGT would produce. Further, there is no current requirement in B.C. for market purchases of electricity from external jurisdictions to be from clean or renewable sources or to have offsets for GHG emissions. Hence, the additional GHG related costs for generating in B.C. have the effect of making natural gas-fired generation less attractive than equivalent products from the U.S. markets. The result is that natural gas-fired generation in B.C. is expected to be dispatched very infrequently.

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71 This expected requirement is described in Chapter 4.
72 As identified in Section 4.2.2.2, the GHG Cap and Trade Act provides the Government with the ability to require imports to offset GHG emissions.
SD 10 requires that BC Hydro be capable of generating sufficient electricity from resources in BC to meet its average load forecast assuming only critical water from the Heritage Hydro assets. Being capable of generating in B.C. does not necessarily require BC Hydro to operate its thermal assets uneconomically; however, to meet the intent of self-sufficiency BC Hydro considers that planning to be capable must include both being capable in all respects, including economically, of operating the units to the level of the firm commitment as well as meeting the environmental requirements when operating to that level.

In the modelling of natural gas fired generation in the portfolios, planning requirements and operational impacts were considered.

From a planning perspective, natural gas units are modelled based upon their expected capability to generate both in terms of capacity and energy. This capability contributes to meeting customers’ dependable capacity and firm energy requirements.

From an operations perspective, based upon current forecasts of market prices, natural gas fired generation located in B.C. would never be dispatched unless there was either a peak period capacity shortfall or a market access restriction.

The Mid C market heat rate associated with the electricity price forecasts is below the effective heat rate (including the GHG offset and carbon tax) for both new CCGTs and SCGTs that might be included in portfolio analysis. Figure 5-3 and Figure 5-4 provide a comparison of the heat rate of a new 250 MW CCGT and a new 100 MW SCGT to the market heat rate for the mid gas and electric scenario, and Figure 5-5 and Figure 5-6 provide the same for the high gas and electric scenario. The market heat rate in each of the figures presents the average heat rate and the range of heat rates at the 10th and 90th percentile of hourly exceedance of the forecast market prices for each year.

Figure 5-3 to Figure 5-6 show that new natural gas fired generating units in the portfolio analysis would not be expected to run so long as there was transmission capacity available. The only exception is shown in Figure 5-5, where under the conditions of high market prices and the lowest scenario of GHG offset costs there is a small percentage of the market heat rates that rise above the cost of a CCGT starting in 2023. Such a small percentage would not likely be sufficient to cause a CCGT to be started for economic dispatch.
Figure 5-3  Effective Heat Rate of a CCGT as compared to the Market (Mid Market Price Forecast)

Figure 5-4  Effective Heat Rate of a SCGT as compared to the Market (Mid Market Price Forecast)
As a result, any natural gas-fired unit that is committed in the portfolio analysis for its capacity or energy contribution to BC Hydro’s requirements for dependable capacity or firm
energy results in the unit entering into service and never forecast to run. The SO commits
new generation based on perfect foresight, and reflects the implicit value of the relatively low
capital cost of natural gas-fired generating units that avoids GHG offset costs and carbon
taxes by replacing all generation that would have come from that unit in the planning horizon
with market purchases.

The issue of planned contribution to dependable capacity and firm energy for self-sufficiency
reasons but never expected to operate was especially seen in model choices between
CCGT and SCGT gas plants. CCGTs are more capital intensive and therefore are expected
to operate at higher capacity factors than SCGTs. For a base load CCGT type gas plant, the
facility would only be built if there was an expectation that it would operate on a consistent
basis with a relatively high average capacity factor. If a plant was expected to operate
infrequently, one would instead rely on a SCGT type peaking plant. While SCGTs are low
efficiency, they are capable of long term sustained dispatch and could be counted on for
high capacity factor operation. The economic result in the perfect foresight modelling world
is to commit SCGTs in preference to CCGTs even in high capacity factor energy
requirement cases, knowing that the unit will be displaced with market purchases and never
run.

The above inconsistency does not reflect the possibility that the Government will require the
offset of GHG with respect to any imports. As described in section 4.2.2, the GHG Cap and
Trade Act contemplates such a requirement and leaves its implementation to regulation.

BC Hydro would not build, seek approval or expect to receive approval to construct or
acquire new generation that was never expected to run. BC Hydro believes this would also
be contrary to the intent of the 2007 Energy Plan and SD 10, and include the risk associated
with the implementation of the GHG Cap and Trade Act.

As a result, future natural gas plants were modelled as follows:

• New natural gas plants had a minimum dispatch requirement to reflect the intent of self-
sufficiency in that they would need to be capable of running, including on an economic
basis, if required. If the plants were never intended to run, they would never be built.

Minimum dispatch was modelled as follows:

  SCGT – Minimum 18 per cent operating factor; and
CCGT – Minimum 70 per cent operating factor.

5.3.4 Clean Electricity Target

The 2007 Energy Plan Policy Action 21 (see Table 1-2) commits to “ensure clean or renewable electricity generation continues to account for at least 90 per cent of total generation”. Further, the 2007 Energy Plan states that “Currently in B.C., 90 per cent of electricity is from clean or renewable resources.” BC Hydro understands this target to be based on actual generation output in which 90 per cent of the electricity actually generated in B.C. would be from clean or renewable resources and that market sales would not be netted against actual generation regardless of whether B.C. is a net importer or exporter. In this LTAP, it is assumed that the Provincial target of 90 per cent would apply to BC Hydro, and that BC Hydro would meet the 90 per cent target with its own portfolio of resources.

In the 2008 LTAP, the analysis underlying this Chapter 5 reflects the generation that was selected in the SO simulations without being constrained by the 90 per cent target. This provides a backdrop with respect to the relative implications, if any, of meeting the target. The relative percentage of clean or renewable was calculated and reported for each portfolio analyzed. The information then becomes one of the inputs into the decision criteria behind the action items laid out in Chapter 6.

Two metrics were tracked in the analysis: (1) clean or renewable generation as percentage of BC Hydro’s domestic load; and (2) clean or renewable generation as percentage of BC Hydro’s overall portfolio of supply resources. The minimum dispatch requirements described in Gas Plant Modelling were maintained for the calculation.

5.3.5 ILM Upgrade Project – 5L83

5L83 is a significant resource in the analysis in the 2008 LTAP. As identified in Chapter 2, the LM/VI load/resource balance is relatively tight, and results in a requirement for 900 MW of Burrard to be reliably available at least until the project is in-service or some other resource option can be available to provide any supply shortfall.

BC Hydro has structured its analysis first assuming that 5L83 will be in service on time; and second to be prepared for the possibility of up to a five year delay. The selection of five years to be the delay period was based on the following:
BCTC’s evidence in its CPCN application generally identified possible ranges of delay of up to three years for technical and project management reasons;

- There remain significant, but unquantifiable, challenges that may go beyond the scope of the above technical or project management control;

- The general lead time, from a planning perspective (including the need to acquire new supply resources) is approximately five years, anything shorter must be dealt with through operational contingency plans; and

- The impact of being short of capacity in the LM/VI region would be quite significant, resulting in a need to ensure that the risk could be covered from both an operational and planning timeframe.

The 5L83 in-service delay risk mitigation is shown in the plans for Burrard in section 5.4 and in the Transmission Contingency Plans in section 6.4.3.

5.3.6 Resource Portfolios

The portfolio analysis was undertaken to create each of the scenarios identified in the Risk Framework. The key issues to be analysed were based upon the base 11 scenarios, shown in Table 5-4 and then further options/restriction were introduced to address further considerations.

The characteristics of the portfolios associated with the base 11 scenarios are as presented in Table 5-4. In this Table, the “Load Growth” and “DSM Scenario” columns are shown as an identifier of what makes up the small, mid and large gap. For example “Small Gap” is, by design the combination of low load growth and the high outcome scenario of DSM Option A.
Table 5-4 Portfolios associated with the Base 11 Scenarios

<table>
<thead>
<tr>
<th>Base 11 Scenarios</th>
<th>Load Growth</th>
<th>DSM Scenario</th>
<th>Cost of Thermal</th>
<th>BGS firm GWh</th>
<th>Site C</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>Gas</td>
<td>GHG</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Small</td>
<td>Low A - High outcome</td>
<td>Low Low</td>
<td>3000</td>
<td>Not considered</td>
<td></td>
</tr>
<tr>
<td></td>
<td>Low A - High outcome</td>
<td>Mid Mid</td>
<td>3000</td>
<td>Not considered</td>
<td></td>
</tr>
<tr>
<td></td>
<td>Low A - High outcome</td>
<td>High High</td>
<td>3000</td>
<td>Not considered</td>
<td></td>
</tr>
<tr>
<td>Moderate</td>
<td>Low A - Mid outcome</td>
<td>Low Low</td>
<td>3000</td>
<td>Not considered</td>
<td></td>
</tr>
<tr>
<td></td>
<td>Low A - Mid outcome</td>
<td>Mid Mid</td>
<td>3000</td>
<td>Not considered</td>
<td></td>
</tr>
<tr>
<td></td>
<td>Low A - Mid outcome</td>
<td>High Mid</td>
<td>3000</td>
<td>Not considered</td>
<td></td>
</tr>
<tr>
<td></td>
<td>Low A - Mid outcome</td>
<td>High High</td>
<td>3000</td>
<td>Not considered</td>
<td></td>
</tr>
<tr>
<td></td>
<td>Low A - High outcome</td>
<td>Low Low</td>
<td>3000</td>
<td>Not considered</td>
<td></td>
</tr>
<tr>
<td></td>
<td>Low A - High outcome</td>
<td>Mid Mid</td>
<td>3000</td>
<td>Not considered</td>
<td></td>
</tr>
<tr>
<td></td>
<td>Low A - High outcome</td>
<td>High High</td>
<td>3000</td>
<td>Not considered</td>
<td></td>
</tr>
<tr>
<td></td>
<td>Low A - Low outcome</td>
<td>Low Low</td>
<td>3000</td>
<td>Not considered</td>
<td></td>
</tr>
<tr>
<td></td>
<td>Low A - Low outcome</td>
<td>Mid Mid</td>
<td>3000</td>
<td>Not considered</td>
<td></td>
</tr>
<tr>
<td></td>
<td>Low A - Low outcome</td>
<td>High High</td>
<td>3000</td>
<td>Not considered</td>
<td></td>
</tr>
<tr>
<td>Large</td>
<td>Low A - Low outcome</td>
<td>Low Low</td>
<td>3000</td>
<td>Not considered</td>
<td></td>
</tr>
<tr>
<td></td>
<td>Low A - Low outcome</td>
<td>Mid Mid</td>
<td>3000</td>
<td>Not considered</td>
<td></td>
</tr>
<tr>
<td></td>
<td>Low A - Low outcome</td>
<td>High High</td>
<td>3000</td>
<td>Not considered</td>
<td></td>
</tr>
</tbody>
</table>

1. The portfolio results for the base 11 portfolios are presented in Table 5-5.

Table 5-5 Portfolio Results associated with the Base 11 Scenarios

<table>
<thead>
<tr>
<th>Base 11 Scenarios</th>
<th>Cost of Thermal</th>
<th>Likelihood</th>
<th>PV of portfolios</th>
<th>2012-2016</th>
<th>2012-2027</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>Gas</td>
<td>GHG</td>
<td>Dependable Capacity</td>
<td>Firm Energy</td>
<td>Dependable Capacity</td>
</tr>
<tr>
<td></td>
<td>Thermal</td>
<td>Clean</td>
<td>MW</td>
<td>GWh</td>
<td>Thermal</td>
</tr>
<tr>
<td>Small</td>
<td>Low Low 0.1%</td>
<td>7,809</td>
<td>-</td>
<td>-</td>
<td>-</td>
</tr>
<tr>
<td></td>
<td>Low Mid 6.6%</td>
<td>7,124</td>
<td>-</td>
<td>-</td>
<td>-</td>
</tr>
<tr>
<td></td>
<td>High High 3.3%</td>
<td>6,583</td>
<td>-</td>
<td>137</td>
<td>-</td>
</tr>
<tr>
<td></td>
<td>Low Low 0.5%</td>
<td>11,577</td>
<td>479</td>
<td>137</td>
<td>2,939</td>
</tr>
<tr>
<td></td>
<td>Mid Mid 24.8%</td>
<td>11,529</td>
<td>479</td>
<td>188</td>
<td>2,939</td>
</tr>
<tr>
<td></td>
<td>Mid High 10.7%</td>
<td>11,758</td>
<td>479</td>
<td>188</td>
<td>2,939</td>
</tr>
<tr>
<td></td>
<td>High Mid 31.0%</td>
<td>11,777</td>
<td>-</td>
<td>319</td>
<td>3,940</td>
</tr>
<tr>
<td></td>
<td>High High 13.0%</td>
<td>11,859</td>
<td>-</td>
<td>277</td>
<td>3,940</td>
</tr>
<tr>
<td>Large</td>
<td>Low Low 0.1%</td>
<td>17,692</td>
<td>577</td>
<td>418</td>
<td>3,094</td>
</tr>
<tr>
<td></td>
<td>Mid Mid 6.6%</td>
<td>17,669</td>
<td>577</td>
<td>418</td>
<td>3,094</td>
</tr>
<tr>
<td></td>
<td>High High 3.3%</td>
<td>16,490</td>
<td>-</td>
<td>575</td>
<td>8,456</td>
</tr>
</tbody>
</table>

Note: The large gap, high gas scenario includes Mica Units 5 and 6 in addition to the Clean and Thermal resources identified in the Table. The units were added in 2016 and 2022.

2. A summary of the results of all portfolios analyzed in this Chapter is provided in Table 5-48.

3. Details with respect to the results of the analysis of each of the portfolios are provided in Appendix F16.

5.4 Burrard Generating Station

5.4.1 Introduction

7. A key issue for the 2008 LTAP: What is the future role of Burrard?
From a system reliability and security perspective, Burrard’s major contribution is supplying its capacity to the LM/VI region. The LM/VI region, the Province’s major load centre, has limited local generation and capacity constraints on transmission. In particular, Burrard will be required to provide 900 MW of capacity at least until 5L83 is complete. While the current expected in-service date of 5L83 is October 2014, BC Hydro is developing its contingency plans in manage up to a five-year delay. Therefore, BC Hydro’s current plan is that Burrard must be capable of reliably providing its capacity and energy capability at least through 2019.

Burrard’s energy contribution is a secondary issue to maintaining a reliable and secure system, however, increasing usage of Burrard to generation electricity could negatively impact its ability to provide capacity for both technical and environmental permit/social license reasons.

To assess the impact of Burrard’s contribution to the system and the appropriate form that the Burrard plant should maintain, BC Hydro has:

- Reviewed Burrard’s historical role, its current operation and its contribution to dependable capacity and firm energy;

- Provided results of technical studies undertaken by AMEC on Burrard’s health and the implications on BC Hydro’s ability to rely upon and operate the plant;

- Reviewed the environmental and social license study undertaken by RWDI on BC Hydro’s ability to operate Burrard;

- Provided an analysis of the impacts of maintaining Burrard in its current configuration with varying levels of energy contribution; and

- Provided both the technical, environmental and social considerations with respect to rebuilding Burrard.

**5.4.1.1 Burrard History**

Burrard is a six unit, 900 MW natural gas-fired generating plant located on Burrard Inlet near Port Moody. Burrard began commercial operation in the early 1960s prior to the development of major hydroelectric generation on the Peace and Columbia Rivers. During the 1960s, Burrard operated as a base load plant, but following completion of major new hydro plants on the Peace and Columbia Rivers in the late 1960s and early 1970s, the
operation changed to that of a swing plant. That is, the operation varies in response to available energy from the major hydroelectric plants, gas prices and external market conditions.

Figure 5-7 shows a chronological plot of actual generation from Burrard over its operating life. The swing operation of Burrard is reflected in the historical annual outputs from Burrard which show that, since 1970, the plant has undergone seven years of relatively heavy operation (i.e., more than 3000 GWh/yr), seven years of intermediate operation (i.e., between 1000-3000 GWh/yr) and 24 years of low operation (i.e., less than 1000 GWh/yr). The historical average annual generation level corresponds to approximately 1100 GWh/yr within the bounds of 4200 GWh/yr (1989) and zero GWh/yr (mid 1980’s).

Following a period of heavy operation in 1989 and 1990, public and regulatory concerns with Burrard were raised with respect to its local air emissions. The primary concern was with the emission of oxides of nitrogen (NOx) which contribute to the formation of ground level ozone or smog which was becoming a chronic air pollution problem within the Lower Fraser Valley (LFV) air shed. At full output, Burrard was one of the largest point sources for NOx emissions in the Lower Mainland.
In response to these concerns and after extensive studies, Burrard’s air permit was modified by Metro Vancouver\textsuperscript{73} to require installation of Selective Catalytic Reduction (SCR) equipment on the Burrard boilers to reduce NOx emissions to more acceptable levels (SCR removes approximately 80 per cent of NOx from the boiler exhaust gases). The schedule imposed by Metro Vancouver called for the addition of SCRs at the rate of one unit per year commencing in 1995. In addition to proceeding with installation of the SCRs, BC Hydro also initiated other major capital work on the Burrard units to modernize and upgrade equipment and control systems. The target of the program, referred to as the Burrard Upgrade Project (BUP), was to achieve commercial unit availability levels of approximately 85 per cent and provide a minimum ten-year life extension for the plant. The BUP amounted to a total capital investment of approximately $200 million. Approximately one half of the capital investment related to the NOx emission abatement measures.

5.4.1.2 Dependable Capacity

Prior to 1998, Burrard was not relied on as a source of dependable capacity. The primary reason was that fuel supply arrangements were not firm on a year-round basis. At the time, Burrard’s primary source of fuel was seasonal gas available under contractual arrangements with Terasen. These arrangements provided little or no supply during the winter period. Similarly, the fuel transportation arrangements to the plant were interruptible and would be curtailed during periods of high gas demand on the Terasen system (which coincided with periods of high demand on the BC Hydro system).

In 1998 when the seasonal gas contract terminated, a firm gas transportation agreement was concluded with Terasen to enable Burrard to have essentially unrestricted access to the Huntingdon/Sumas market hub. The removal of the fuel transportation restriction meant that BC Hydro could rely on the full net capacity output of Burrard as dependable capacity. Assuming all six units are operational, the net generation would be 905 MW which is the current long term dependable capacity value assumed in planning load/resource balances.

In 2001, some Burrard units were temporarily removed from generation mode, such that only three units were available as dependable capacity (450 MW). However, in recent years, as BC Hydro experienced substantial load growth and the capability of both the generation and transmission system have been more fully utilized, Burrard has become a much more

\textsuperscript{73} Formerly the Greater Vancouver Regional District.
significant resource including now being needed to meet peak load conditions in the LM/VI region. Recently, two of the mothballed units have been recalled such that the plant currently has five of six units available in generating mode. The sixth unit is expected to be recalled by October 2008, such that the full 900 MW of dependable capacity may be relied on for operational and planning purposes starting this fall.

5.4.1.3 Energy Capability

Burrard’s energy capability for planning purposes to date has been set at 6,100 GWh/year. BC Hydro has never been able to utilize the full energy capability as a combination of effects including intra-year hydrological variability, actual plant capability and the availability of electricity in the markets create an operating environment that is not conducive to extended high-output operation.

Figure 5-8 shows the operating pattern for Burrard determined from planning capability studies which are based on Burrard output being displaced whenever the Heritage Hydroelectric system and IPP resources produce “secondary” energy (i.e., energy available when water conditions are greater than critical stream flows). These capability assessments do not include displacement by non-firm energy from external markets. The capability analysis shows that Burrard would be expected to run at 6,100 GWh for a large part but not all of a critical water sequence. The studies show that at most the plant would provide approximately 5,000 GWh/year on average through the critical period. Under these assumptions, Burrard’s operation will be variable as shown in Figure 5-8 such that expected average annual generation from Burrard would be approximately 2600 GWh/yr.
5.4.2 Recent Burrard Studies

Since the 2006 IEP/LTAP, BC Hydro commissioned consultant studies to assess:

- The technical and economic issues related to maintaining existing Burrard over the short and long term at various scenarios of capacity and energy capability. The key goals of these studies were to assess the capital and OMA funding requirements for each scenario, and to assess the extent to which each of the operating scenarios could be accommodated from technical and “social license to operate” perspectives. The following scenarios were considered:
  - Scenario 1 - as a 900 MW peaking plant with energy output limited to 600 GWh/yr (capacity factor of approximately ten per cent);
  - Scenario 2 - as a 900 MW plant capable of intermediate energy operation with an output of 3000 GWh/yr; and
  - Scenario 3 - as a 900 MW plant capable of base load operation with energy output of 6000 GWh/yr.
• Potential issues with the plant permits (air and water) and the broader “social license to operate” perspective for the existing plant assuming levels of energy output consistent with the technical study identified in (1):
  ‣ The estimated costs and schedule for rebuilding Burrard with either new SCGT or CCGT technology; and
  ‣ Issues associated with attempting to obtain permits for rebuilding options (SCGT or CCGT) identified in (3).

5.4.2.1 AMEC Study – Maintain Burrard

For maintaining Burrard in its current configuration, the key findings of AMEC are:
• Burrard is in reasonably good condition for its age, in part reflective of its relatively low operating hours;
• Burrard has recently been maintained to provide service consistent with the reliability/availability of four units (600 MW), with two spare units (300 MW). The plant is currently not in adequate condition nor does it have adequate spare parts to maintain a sustained six unit operation (900 MW) until 5L83 is in-service;
• However, it would likely be technically feasible to maintain Burrard as a source of 900 MW of dependable capacity that is capable of producing 600 to 6000 GWh/year of firm energy for the 20-year planning horizon:
  ‣ This should be confirmed by detailed condition assessments of the units followed by significant up-front capital expenditures to ensure that the generators will be available on a reliable basis;
  ‣ The key aspects of the capital program will be to provide critical spare equipment for the units (e.g., turbine rotors, generator stators, transformers). Also, the program will include upgrading the outdated control systems on units 1-3; and
  ‣ Of the six units at the plant, units 4-6 are a relatively newer vintage and in better condition while units 1-3 are an older vintage and are expected to require more refurbishment. Further, the older units 1-3 have been used as synchronous condensers for Voltage-Ampere-Reactive support, resulting in significant cumulative operating hours of the electrical components.
• Attempting to operate Burrard as a continuous baseload plant (i.e., Scenario 3 with output of 6000 GWh/yr) may be technically feasible, but involves some elevated degree of risk:
  ‣ The risk major unit failures (resulting in very long or terminating unit outages) can be reduced, while failure of some unit components is expected;
  ‣ The availability of critical spares and upgraded controls will largely mitigate the risk of these failures and minimize repair costs and downtime; and
  ‣ AMEC has indicated that an annual availability level of 85 per cent for the Burrard units may be achievable, which would accommodate base load operation.

The following provides an overview of the key costing and technical information for the three operating scenarios identified in above. These data form the inputs for the portfolio analysis of the existing Burrard options to be assessed in the 2008 LTAP.

**OMA and capital funding assumptions**

The AMEC study identifies schedules of capital and OMA expenditures that would be required to achieve the operational requirements of each of the three operating scenarios identified for the existing plant. Table 5-6 shows the average annual capital and OMA expenditures of each schedule for:

• The first seven years (2009 to 2015); and
• The last 13 years (2016 to 2028).

Table 5-6 Annual OMA and Capital Funding for Alternative Burrard Operating Scenarios ($M/yr)

<table>
<thead>
<tr>
<th>Period</th>
<th>Scenario 1 (900 MW/600 GWh)</th>
<th>Scenario 2 (900 MW/3000 GWh)</th>
<th>Scenario 3 (900 MW/6000 GWh)</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>Capital</td>
<td>OMA</td>
<td>Capital</td>
</tr>
<tr>
<td>Average 2009-2015</td>
<td>26</td>
<td>15</td>
<td>31</td>
</tr>
<tr>
<td>Average 2016-2028</td>
<td>6</td>
<td>13</td>
<td>7</td>
</tr>
<tr>
<td>Average 20 yrs</td>
<td>13</td>
<td>14</td>
<td>16</td>
</tr>
<tr>
<td>Levelized 20 yrs</td>
<td>16</td>
<td>14</td>
<td>19</td>
</tr>
</tbody>
</table>

(Adapted from: AMEC report attached to the 2008 LTAP as Appendix J1, and in particular Appendices 2, 3 and 4 of that report).

The above schedules for Scenario 1 indicate that, for the period prior to 5L83’s planned ISD, an average of $26 million/year of up-front capital funding would be required to maintain Burrard as a source of dependable capacity for six unit operation. The precise level of
capital funding will be contingent on condition assessment inspections to be undertaken on the units during the first two years. A major portion of the capital funding relates to “availability capital” to provide spares for key components (e.g., turbine rotors, generator stators, transformers) as well as funding for upgrading the control systems on units 1-3. The capital funding requirement drops significantly after 2015 to an average of $6 million/year.

Given that full Burrard capacity will be required for reliability reasons at least until 5L83 is in-service, current planning studies assume that the minimum funding for the existing Burrard plant will be in accordance with the Scenario 1 capital and OMA schedules shown in Table 5-6. The funding schedules for Scenarios 2 and 3 shown in Table 5-6 indicate that incremental capital and OMA expenditures will be required to achieve higher levels of continuous energy capability for Burrard above the 600 GWh/year of peaking-only operation in Scenario 1.

**Performance and emissions data**

Table 5-7 provides a summary of performance and emissions data assumed for the existing Burrard plant in each of the three scenarios.

<table>
<thead>
<tr>
<th>Parameter</th>
<th>Units</th>
<th>Scen. 1</th>
<th>Scen. 2</th>
<th>Scen. 3</th>
</tr>
</thead>
<tbody>
<tr>
<td>Dependable Capacity</td>
<td>MW</td>
<td>905</td>
<td>905</td>
<td>905</td>
</tr>
<tr>
<td>Annual Capacity Factor</td>
<td>%</td>
<td>8%</td>
<td>38%</td>
<td>77%</td>
</tr>
<tr>
<td>Annual Firm Energy</td>
<td>GWh/yr</td>
<td>600</td>
<td>3050</td>
<td>6100</td>
</tr>
<tr>
<td>Heat Rate (HHV)</td>
<td>GJ/MWh</td>
<td>10.6</td>
<td>10.6</td>
<td>10.6</td>
</tr>
<tr>
<td>Project Life</td>
<td>years</td>
<td>20</td>
<td>20</td>
<td>20</td>
</tr>
<tr>
<td>Gas Transportation Cost</td>
<td>$M/yr</td>
<td>10</td>
<td>10</td>
<td>10</td>
</tr>
<tr>
<td>NOx Emission Factor</td>
<td>kg/MWh</td>
<td>0.11</td>
<td>0.11</td>
<td>0.11</td>
</tr>
<tr>
<td>CO2 Emission Factor</td>
<td>kg/MWh</td>
<td>520</td>
<td>520</td>
<td>520</td>
</tr>
</tbody>
</table>

Gas transportation costs are based on the fixed charges under the Bypass Transportation Agreement with Terasen. Heat rate and emission factors reflect the characteristics at full load operation.

**Unit availability**

AMEC has indicated that if the proposed program of capital funding is implemented, the annual availability factor for the existing Burrard units could be near 85 per cent. BC Hydro has traditionally assumed that the planning availability factor for the units would be...
82.5 per cent, comprising one month per year for planned maintenance and ten per cent
downtime for forced outages. Given that the historical assumption is close to the estimate
identified by AMEC assuming the proposed refurbishment is completed, no change was
made to the previous planning assumptions for the unit availability factors.

Scenario 3 assumes an annual energy capability of 6,000 GWh/year from Burrard, which is
equivalent to a 77 per cent annual capacity factor and an output factor when available of
almost 94 per cent. This leaves almost no margin to accommodate unplanned outages, unit
start-up failures or constraints such as potential cooling water constraints in the summer
months which may, at times, limit Burrard output to 4 units at full load. The AMEC report
states “… such a Scenario is not realistic for a plant that is currently 32 to 40+ years old and
will be 52 to 60 + years old in 20 years.”

5.4.2.2 RWDI Study – Maintain Burrard

Environmental Risk: Burrard’s Social License to Operate

Burrard is a source of NOx, carbon monoxide, sulphur dioxide and particulate matter 10
microns or less in diameter (PM10) and 2.5 microns or less in diameter (PM2.5). Ozone,
although not directly emitted by Burrard, may be formed through photochemical reactions
between NOx and volatile organic compounds. Recent studies indicate that health effects
may be experienced at any exposure to ozone and PM2.5, since there is no threshold for
these pollutants. Small amounts of other pollutants not governed by Federal, Provincial or
regional government air quality objectives or standards are also emitted when Burrard
operates; an example is the ammonia from mitigation measures to reduce NOx levels. In
addition, the combustion of natural gas at Burrard produces GHGs.

Burrard operates in the LFV air shed, one of three air sheds in Canada identified by
Environment Canada and the Canadian Council of Ministers of Environment (CCME) during
the 1980s as requiring the implementation of remedial actions due to ozone levels
exceeding the maximum acceptable level. Furthermore, the LFV does not yet fully comply
with the CCME’s Canada-Wide Standard (CWS) for ground-level ozone. The B.C.
Government has committed that air sheds in B.C. will be in compliance with the CWS by

74 “AMEC Condition Assessment and Alternative Configuration Study; Burrard Generating Station Current
Configuration” Section 7.3 Page 82; attached as Appendix J1.
75 The Canadian Council of Ministers of the Environment’s Canada-Wide Standard for Particulate Matter (PM)
and Ozone states that there is no apparent threshold for the effects of these two pollutants on human health.
2010. Metro Vancouver, the government agency with regulatory authority over air quality in
most of the LFV in general and over Burrard’s Air Emission Permit in particular, replaced its
air quality objectives with much more stringent objectives for NOx, PM2.5 and other
pollutants in 2005, and adopted a new Air Quality Management Plan that emphasizes the
reduction of total emissions of pollutants. Metro Vancouver has opposed the siting of new
thermal generating facilities within the LFV.

BC Hydro retained RWDI to provide an assessment of the consent to operate risks to
Burrard for the next twenty years as currently configured for four scenarios. For purposes of
the RWDI analysis, “social license to operate” is defined as “the notion of license to operate
derives from the fact that every company needs tacit or explicit permission from
governments, communities and other stakeholders to do business”:

• Scenario 1: in its current peaking function (approximately 500 GWh/y); RWDI is of the
  view that since Burrard currently has a social license to operate Burrard in its current
  function, Scenario 1 should be achievable, despite predicted ambient air quality
  exceedances;

• Scenario 2: as a base-load plant for approximately 3,000 GWh/year. As BC Hydro has an
  existing social licence to operate Burrard as a peaking facility and has operated at
  Scenario 2 levels in the recent past (2001, 2000, 1998), RWDI predicts that the existing
  social licence could accommodate a change to increase expected annual operations to a
  base-load facility for approximately 3,000 GWh/year;

• Scenario 3A: as a base-load plant for approximately 6,100 GWh/y every year. RWDI
  concludes that operating every year (Scenario 3A) at a level greater than historical levels
  during a time in which environmental concerns are high could not be accommodated
  within the existing social licence; and

• Scenario 3B: as a base-load plant with the following pattern during a 60-year period:
  6,100 GWh/year for four low-water years, 5,000 GWh/year for one low-water year and no
  more than 3,000 GWh/year the remaining 55 years. RWDI concludes that while it may be
  possible to gain public support for Scenario 3B if it can be demonstrated to the public that
  occasionally operating Burrard at 6,100 GWh/year or 5,000 GWh/year is required to meet
  provincial electricity needs during low-water years. However, RWDI also concludes that
  there is likely to be strong opposition from the Fraser Valley Regional District, some
Fraser Valley residents and groups who oppose the siting or development of electricity generation in the Lower Mainland and who will use the fact that under scenario 3B Burrard will be the largest source of GHG emissions in the Province, and that emissions of NOx will nudge up against the Metro Vancouver air quality objectives. RWDI states that the only way to renegotiate the social license to encompass Scenario 3B is for BC Hydro to conduct a stakeholder engagement program.

RWDI’s report, entitled “Burrard Thermal Generating Station: Consent to Operate Risk Analysis”, is attached as Appendix J3. BC Hydro accepts RWDI’s conclusion that the risk of losing the Burrard social license increases significantly if Burrard as currently configured is operated at greater than that configured in Scenario 2 (3,000 GWh/year) or possibly past the operating levels experienced in the recent history from 1998, 2000 and 2001 (average annual output of 3,250 GWh/year with a maximum of 3,963 GWh/year). RWDI points out that Burrard has never operated above 4,500 GWh/year. The social license risk of operating Burrard above these levels could negatively impact its availability as a supply source that can be depended on.

5.4.2.3 Maintain Burrard – Analysis

Burrard is required for 900 MW of capacity both to meet overall system peak load requirements as well as to meet LM/VI capacity requirements at least until 5L83 is in-service. The 5L83 ISD is expected to be in service in October 2014, however, BC Hydro is planning as a contingency to have Burrard available until at least 2019 to reflect possible 5L83 delays. The essential objective of Burrard’s service is to meet the capacity requirements, and BC Hydro plans to avoid doing anything that would increase the risk of Burrard not being able to meet that objective.

The AMEC study indicated that with adequate funding and executing the appropriate refurbishment plan, which includes critical sparing, BC Hydro may be able to rely on the plant for 6 units of capacity. The report also suggests that the plant is less capable of sustained operation at higher output levels due to aging equipment, expected forced outages and required maintenance down times.\textsuperscript{76} To the extent that the plant is driven to operate more frequently, it will be less capable of providing its capacity benefits. Without the

\textsuperscript{76} “AMEC Condition Assessment and Alternative Configuration Study; Burrard Generating Station Current Configuration” Section 7.3 Page 82.
incremental funding, the Burrard facility is expected to have the effective capability of a four unit plant.\textsuperscript{77}

The RWDI report indicated that, provided Burrard manages current exceedance issues, it has a social license to operate to historic levels. This has been described in the previous section. From the capability study shown in section 5.4.1.3, if Burrard were to be relied on for 6,100 GWh/year, it would be expected to run at that level for multiple years in a dry water sequence. Both of these studies indicate that Burrard is very likely not capable of operating at the 6,100 GWh/year level.

**Portfolio Analysis**

In the portfolio analysis Burrard was modelled as contributing 900 MW of dependable capacity and a range of contribution to BC Hydro's firm energy capability of 2000, 3000 and 4000 GWh/year and it was assumed that there were no must run requirements for Burrard. Burrard's energy contribution must be consistent with SD 10 in terms of being capable of operation and having an appropriate reliance on imports and Heritage Hydro non-firm energy. Capable of operation to the level of firm energy contribution includes the following:

- The plant must be technically capable of operating at that level on a prolonged basis;
- The plant must operate within its environmental permits; and
- The plant must have a social license to operate at that level.

Hence, the range was intended to reflect the probable range over which Burrard is expected to be capable of operating on a consistent basis in line with the technical assessment and social licensing risk, some expectation of IPP non-firm energy supply that would contribute to displacing Burrard's energy contribution and Burrard's historical role in the system.

This modelled operation is different than the modelling of new natural gas fired generation that is described in section 5.3.3. The modelling of other new natural gas-fired generation reflected the unit commitment view that a new facility would not be built unless it was expected to run.

The results of the analysis before considering any incremental benefit from REC-related sales pursuant to U.S. state RPS requirements (described in section 4.5), and absent

\textsuperscript{77} Ibid, Page s3
Burrard’s capability, availability or social licence considering risks, are as shown in Table 5-8.

<table>
<thead>
<tr>
<th>Gap</th>
<th>Cost of Thermal</th>
<th>Burrard Firm Energy per Year</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>Gas</td>
<td>GHG</td>
</tr>
<tr>
<td>Low</td>
<td>Low</td>
<td>0.6%</td>
</tr>
<tr>
<td>Mid</td>
<td>Mid</td>
<td>31.0%</td>
</tr>
<tr>
<td>Mid</td>
<td>Mid</td>
<td>13.4%</td>
</tr>
<tr>
<td>High</td>
<td>Mid</td>
<td>38.8%</td>
</tr>
<tr>
<td>High</td>
<td>High</td>
<td>16.3%</td>
</tr>
</tbody>
</table>

Weighted Present Value

A sensitivity analysis of the above portfolios that included the three scenarios of incremental prices for sales of RECs in the WECC (described in section 4.5) was completed on the above. The results of this analysis are provided in Figure 5-9.
The above analysis shows that the differential in present value ($PV$) costs of the portfolios with the range of Burrard firm energy capabilities drops as the value of RECs in the market increases. This analysis is strictly based on the economics of operating Burrard for energy purposes and does not reflect potential implications of the operation on the social license to operate or availability of dependable capacity.

5.4.3 Rebuild Burrard

5.4.3.1 Rebuild Burrard - AMEC

AMEC also examined alternatives for rebuilding Burrard. These were described as “alternative configurations” and included rebuilding with new SCGT and CCGT units as summarized below:

SCGT A and B:
• The existing units 1-3 are the oldest units in the plant; generally have the highest operating hours and least modern control systems. These would be replaced with new SCGT units equivalent to 300-500 MW of capacity;

• Units would be placed at the east of end of the existing power house (i.e., adjacent to units 1-3). Development would be undertaken such that existing plant dependable capacity of 900 MW would be maintained during construction (i.e., existing units would generally not be removed from service until new units are operational). This implies that rebuilding could commence prior to 5L83 being in-service;

• In the longer term, existing units 4-6 (450 MW) would be retained in an operational mode. Other existing units would be partially demolished, but could be retained for synchronous condenser operation or as a source of spares for units 4-6;

• Rebuilding with SCGT technology identified as either “F” class machines (SCGTA) (e.g., 3x170 MW = 510 MW) or new large aero-derivative machines (SCGTB) (e.g., 3 LMS100 units with capacity of 300 MW):
  ▷ For “F” class machines, it was identified that SCR may not be feasible given high exhaust temperatures. These units are typically used as part of a CCGT facility;
  ▷ The smaller capacity aero-derivative machines take more space per unit than the “F” class machines, resulting in space available for 300 MW of capacity at the east end of the plant rather than 510 MW. If 900 MW were to be maintained at the plant after the installation of three LMS100s, it would require maintaining the existing unit 3; and

• The construction time line for this option would have an expected earliest ISD of 2014. Hence, albeit the construction could begin prior to 5L83 being in-service, the expected ISD would not be appreciably earlier than the currently planned 5L83 ISD. As a result, Burrard would still be required to be reliably available in its current form until 2014 and would still require the refurbishment work.

Half CCGT:

• Existing units 1-3 would be replaced with 550 MW of new CCGT capacity. A new powerhouse to the east of existing units 1-3 would be constructed to house the gas turbine generators and heat recovery steam generators;

• Existing unit 1 would be replaced with a new steam turbine generator;
• Full capacity of 900 MW would be maintained from existing Burrard units during the
  construction provided that operation without SCRs was permitted;

• In the longer term, existing units 4-6 (450 MW) would be retained in operational mode.
  Units 2 and 3 could serve as synchronous condensers or as a source of spares; and

• The construction time line for this option would have an expected earliest in-service date
  of 2014. Again, this implies that the existing Burrard units would need refurbishment work
  to ensure they are reliably available until 2014.

Full CCGT:

• This would provide a second 550 MW of CCGT stage in addition to the first stage
  identified above (total capacity of 1100 MW):

• The second stage would involve constructing new gas turbine generators and heat
  recovery steam generators in the space currently occupied by existing units 2 and 3;

• A new steam turbine generator would be constructed in the space of existing unit 4; and

• The construction time line for this option would have the first stage in-service in 2014 and
  the second stage in-service in 2015.

Comparison of the SCGT and CCGT Options to the Burrard Refurbishment:

Salient planning data on the redevelopment options for Burrard are shown in Table 5-9.
Table 5-9  Planning Assumptions for Redevelopment Options for Burrard

<table>
<thead>
<tr>
<th></th>
<th>Half CCGT</th>
<th>Full CCGT</th>
<th>SCGT A (F Class)</th>
<th>SCGT B (LMS100)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Project type</td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Dependable Capacity</td>
<td>MW</td>
<td>550</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Annual Capacity Factor</td>
<td>%</td>
<td>91%</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Annual Firm Energy</td>
<td>GWh/yr</td>
<td>4400</td>
<td>8800</td>
<td>3600</td>
</tr>
<tr>
<td>Heat Rate (HHV)</td>
<td>GJ/MWh</td>
<td>7.385</td>
<td>7.385</td>
<td>11.000</td>
</tr>
<tr>
<td>Direct Capital Cost</td>
<td>$M</td>
<td>582</td>
<td>1060</td>
<td>360</td>
</tr>
<tr>
<td>Fixed O&amp;M</td>
<td>$M/yr</td>
<td>3.7</td>
<td>5.9</td>
<td>1.1</td>
</tr>
<tr>
<td>Variable O&amp;M</td>
<td>$/MWh</td>
<td>4.2</td>
<td>4.7</td>
<td>5.0</td>
</tr>
<tr>
<td>Project Life</td>
<td>yrs</td>
<td>25</td>
<td>25</td>
<td>30</td>
</tr>
<tr>
<td>Project Lead Time</td>
<td>yrs</td>
<td>7</td>
<td>7</td>
<td>6</td>
</tr>
<tr>
<td>Gas Transportation Cost</td>
<td>$/yr</td>
<td>5</td>
<td>10</td>
<td>5</td>
</tr>
<tr>
<td>Compressor fuel gas</td>
<td>%</td>
<td>0.5%</td>
<td>0.5%</td>
<td>0.5%</td>
</tr>
<tr>
<td>NOx Emission Factor</td>
<td>kg/MWh</td>
<td>0.02</td>
<td>0.02</td>
<td>0.16</td>
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<tr>
<td>CO2 Emission Factor</td>
<td>kg/MWh</td>
<td>367</td>
<td>367</td>
<td>552</td>
</tr>
</tbody>
</table>

Note: All costs in Jan. 2008 dollars

1. The relative levelized costs in $/kW-year based on capacity factor are provided in Figure 5-10 and Figure 5-11. As can be observed in this figure:

2. • the cost of refurbishing the existing plant is lower than that of the SCGT at all capacity factors; and

3. • refurbishing the existing station would result in lower overall costs than the CCGT options as long as the average annual capacity factor remained at or below 25 per cent based on the mid gas price forecast and 15 per cent if based on the high gas price forecast.
For rebuilding Burrard in its current configuration, the key findings of AMEC are:
Redeveloping part or all of Burrard with either new SCGT or CCGT units would be technically feasible and could be accomplished largely without reducing total plant capacity below 900 MW during the construction period of the new units;

The earliest ISDs would be 2014 for new SCGT units and new CCGT units; and

Given a reasonable expected range of operating levels of Burrard in any of the configurations over the next ten years, the cost of rebuilding Burrard as either an SCGT or a CCGT is expected to be higher than the cost of refurbishing the existing plant.

Refer to the AMEC report attached as Appendix J2 for further detail.

5.4.3.2 Rebuild Burrard – RWDI Study

BC Hydro retained RWDI to conduct a permitting risk assessment of the three principle rebuild Burrard options. In all three cases, the following Government agency approvals would be required:

- An EAC pursuant to BCEAA. The Reviewable Projects Regulation provides that a new thermal electric facility with a rated nameplate capacity of greater than or equal to 50 MW, or a modification of an existing thermal electric facility having a rated nameplate capacity that has increased by greater than or equal to 50 MW, is a reviewable project that must be assessed under BCEAA. Even if the rebuild option did not strictly speaking trigger BCEAA, BC Hydro would opt into the B.C. environmental assessment process pursuant to section 7 of BCEAA;

- An assessment pursuant to CEAA as a result of the work close to Burrard Inlet;

- A new Air Emission Permit, or an amendment to the existing Air Emission Permit; and

- A CPCN or BCUC determination pursuant to the UCA.

RWDI concluded that there would be permitting risk with all three rebuild options, as follows:

- SCGT - A Heavy Frame Class "F" SCGT option would be very challenging to permit because NOx and PM emissions would be significantly higher than Burrard as currently configured and CO2 emissions would be eight per cent higher. "Best available control technology" to reduce NOx emissions would be required to attain regulatory and public acceptance. This likely implies that SCR equipment must be installed to keep NOx emission rates at or below the level for the existing Burrard units, thereby eliminating the Heavy Frame Class "F" SCGT option at the present time. A SCGT option that utilized LMS 100 units with SCR would likely be the lowest permitting risk option of the rebuild options;

- One CCGT Unit displacing half of the existing Burrard Units - There would be significant permitting challenges associated with this option; and

- Two CCGT Units displacing all of the existing Burrard Units - This is the highest permitting risk option.

Details are set out in the RWDI report attached as Appendix J4.

5.4.3.3 Conclusion

The following identifies the full range of Burrard options and identifies BC Hydro’s current assessment of feasibility:

- Demolish: Infeasible
  - As identified in Chapter 2, the LM/VI region will be severely capacity constrained until 5L83 is in place or BC Hydro acquires additional capacity from other sources in this region;
  - Demolition is not an option as the Burrard capacity capability must be retained at least until 5L83 is in place.

- Maintain 900 MW/600 GWh: Feasible – Risk: Low
  - BC Hydro is not aware of any similarly sized capacity option in the LM/VI region that is lower cost than Maintaining Burrard;
  - This option would provide the least severe operating requirement for Burrard while maintaining its 900 MW capacity contribution; and
Actual operation may result in annual output in the range of 1,000 to 1,500 GWh for LM/VI capacity reliability until 5L83 is in-service.

- Maintain 900 MW/3000 GWh: Feasible – Risk: Low-Moderate
  - Relying on 900 MW and 3,000 GWh for planning purposes would be nearer the high end of historical operating experience for Burrard. It would be more technically challenging to ensure reliable operation while maintaining its 900 MW capacity contribution; and
  - There has been some historical operating experience near 3,000 GWh/year, providing less permitting or social license risk than would exist for higher operating levels.

- Maintain 900 MW/6000 GWh: Feasible – Risk: High
  - This option would require that Burrard be capable of operating at high capacity factor. Given the age of the plant and expected failures even with the refurbishment, it is unlikely the plant could reliably operate at 900 MW and 6000 GWh/year of output;
  - Increased operating time inherently reduces the likelihood of capacity being available when required and increases the probability and number of major outages that would be expected;
  - 6,000 GWh/year significantly exceeds any historical operation and raises plant social license risks. Committing to rely on the additional firm energy capability may impact the plant’s dependable capacity contribution at risk;
  - Being able to utilize the full 6,000 GWh/year in a critical hydro event would require predicting the event was about to occur, and operating the plant from the outset of the critical period;
  - Relying on firm energy capability for planning purposes that is substantially above the expected operation is inconsistent with self-sufficiency. In B.C., the GHG Cap and Trade Act includes the possibility that electricity imports may require GHG offsets. While it is not known when any underlying regulations may be implemented, it is a clear signal that natural gas-fired generation being used to backstop non-firm imports would include significant risk particularly if the imports were at all material.

- Rebuild SCGT: Feasible- Risk: Moderate - High
This option is more expensive than Maintaining Burrard. Once the existing plant is 
refurbished and has appropriate spares, it will be a low capacity cost option until at 
least 2019 by which time 5L83 will be in place;

Rebuilding Burrard with SCGT technology is not a suitable option at this time as 
Burrard is required to provide reliable capacity until 2014 which would still require 
substantial investment in the existing plant to maintain its reliability;

Rebuilding at this time would put the existing plant emissions permit at risk at the 
same time the 5L83-related permitting is being undertaken;

Absent significant quantifiable benefit to rebuilding, it would be premature to consider 
rebuilding options in advance of more certainty regarding GHG offset requirements 
and costs;

Delay in rebuilding decision may offer the “F” class machines as an option; and

Ultimately, this option is a contingency plan in case of a catastrophic failure of any 
existing Burrard units.

• Rebuild one half CCGT or full CCGT: Feasible – Risk: Very High

It is unlikely that a base load plant would be permitted as a replacement to the existing 
Burrard unit as it fundamental changes the expected operation of the plant;

Rebuilding Burrard with CCGT technology is not a suitable option at this time as 
Burrard would be required to provide reliable capacity until 2014 which would still 
require substantial investment in the existing plant;

Rebuilding at this time would put the existing plant emissions permit at risk at the 
same time the 5L83-related permitting is being undertaken; and

Once the existing plant is refurbished and has appropriate spares, it will be a low 
capacity cost option until at least 2019 by which time 5L83 will be in place.

In summary, the rebuilding options for Burrard are either infeasible or both higher cost and 
higher risk than relying upon Burrard in its current configuration. To ensure that Burrard is 
available to provide the required capacity, BC Hydro is planning actions that minimize the 
risk of the plant being unavailable or available at a reduce capacity. These actions include:
• Reduce planned firm energy commitment to 3,000 GWh to reflect the actual firm energy
  contribution to the BC Hydro system, reduce social license risk and to meet the intent of
  SD 10;

• Funding and implementing the refurbishment plan as proposed by AMEC for the 900 MW
  3000 GWh reliance on Burrard; and

• Delaying any potential plans to rebuild the plant that may raise either social license or
  permitting issues until 5L83 is in place.

5.5 DSM
A key issue for the 2008 LTAP: What is the most appropriate level of DSM in BC Hydro’s
long-term resource plan given economics, deliverability risk, and government policy?

Two levels of DSM were considered in the 2008 LTAP that are distinguished by the names,
DSM Option A and DSM Option B, and by their expected energy savings in F2020 as
follows:

DSM Option A: Expected energy savings of 10,900 GWh per year with associated
capacity savings of 1,900 MW, both including transmission and
distribution loss savings; and

DSM Option B: Expected energy savings of 12,900 GWh per year with associated
capacity savings of 2,200 MW both including transmission and
distribution loss savings.

DSM is a major element in BC Hydro’s plan to fill the load/resource gap through the
planning horizon. If successful, DSM Option A would meet 78 per cent of the forecast
energy gap in F2020. This represents a substantial increase in the level of reliance on DSM
compared to past DSM plans. For example, the second “wave” of DSM launched by
BC Hydro in F2002 targeted 3,600 GWh per year of savings by F2012. By comparison,
planned energy savings in F2020 from DSM Option A are three times this amount. DSM
Option B would provide approximately 20 per cent more energy savings than DSM Option A.

79 These DSM savings figures differ from those presented in Chapter 3 because they incorporate line losses and
the probability assessment. Referring to footnote 1 on page 3-7, these DSM savings figures represent the mid
outcome within the second set of DSM savings figures in this LTAP.
Its magnitude is such that the DSM energy savings would more than offset the 1.4 per cent/year (31.6 per cent cumulative) domestic mid load growth through F2021.

While the DSM Options target a planned level of savings by F2020, the 2008 LTAP recognizes explicitly that DSM savings may turn out to be higher or lower than expected. The LTAP Risk Framework has made an attempt to quantify the uncertainty with respect to the targeted electricity savings in F2020. These uncertainty estimates have been reflected in the probability assessments that were used to set the Low, Mid and High Gaps.

5.5.1 Analysis

To address the key DSM question for the LTAP in light of the above-mentioned uncertainties, the following were analysed.

- The impact of alternative DSM volumes on the load/resource balance;
- An economic analysis of the two DSM Options; and
- The deliverability risk of the DSM savings.

5.5.2 Impact of DSM on the Load/Resource Balance

The first step was to assess the impact of the two DSM Options on the load/resource balance. Table 5-10, Table 5-11 and Table 5-12 present the capacity and energy gaps that would remain after DSM Option A and DSM Option B. The figures assume that only the respective DSM savings are incorporated into the current and committed load/resource gap. No new resources other than DSM are added. In Table 5-10, Table 5-11 and Table 5-12, a positive number indicates a surplus and a negative indicates a deficit. Peak refers to the BC Hydro system peak demand in MW and Energy refers to the BC Hydro annual energy demand in GWh/year.

---

80 A description of this uncertainty analysis is provided in Appendix F14.

81 The following load/resource gap analysis is based on the same gap analysis provided in Chapter 2.
Table 5-10 Remaining Gap with Mid Load/Resource Gap and DSM Options

<table>
<thead>
<tr>
<th></th>
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</tr>
</thead>
<tbody>
<tr>
<td>Mid Gap with DSM Option A</td>
<td></td>
<td></td>
<td></td>
<td></td>
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<tr>
<td>Peak (MW)</td>
<td>382</td>
<td>356</td>
<td>358</td>
<td>37</td>
<td>115</td>
</tr>
<tr>
<td>Energy (GWh/yr)</td>
<td>339</td>
<td>-352</td>
<td>-905</td>
<td>-1,315</td>
<td>-3,258</td>
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<tr>
<td>Mid Gap with DSM Option B</td>
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<td></td>
<td></td>
</tr>
<tr>
<td>Peak (MW)</td>
<td>527</td>
<td>546</td>
<td>588</td>
<td>209</td>
<td>388</td>
</tr>
<tr>
<td>Energy (GWh/yr)</td>
<td>927</td>
<td>502</td>
<td>187</td>
<td>56</td>
<td>-1,837</td>
</tr>
</tbody>
</table>

Table 5-11 Remaining Gap with High Load/Resource Gap and DSM Options

<table>
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<tr>
<td>High Gap with DSM Option A</td>
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<td></td>
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<tr>
<td>Peak (MW)</td>
<td>-180</td>
<td>-262</td>
<td>-319</td>
<td>-697</td>
<td>-671</td>
</tr>
<tr>
<td>Energy (GWh/yr)</td>
<td>-3,085</td>
<td>-4,175</td>
<td>-5,156</td>
<td>-5,956</td>
<td>-8,294</td>
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<tr>
<td>High Gap with DSM Option B</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Peak (MW)</td>
<td>-51</td>
<td>-101</td>
<td>-131</td>
<td>-495</td>
<td>-455</td>
</tr>
<tr>
<td>Energy (GWh/yr)</td>
<td>-2,487</td>
<td>-3,385</td>
<td>-4,195</td>
<td>-4,879</td>
<td>-7,108</td>
</tr>
</tbody>
</table>

Table 5-12 Remaining Gap with Low Load/Resource Gap and DSM Options

<table>
<thead>
<tr>
<th></th>
<th></th>
<th></th>
<th></th>
<th></th>
<th></th>
</tr>
</thead>
<tbody>
<tr>
<td>Low Gap with DSM Option A</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Peak (MW)</td>
<td>947</td>
<td>981</td>
<td>1,047</td>
<td>791</td>
<td>928</td>
</tr>
<tr>
<td>Energy (GWh/yr)</td>
<td>3,730</td>
<td>3,432</td>
<td>3,320</td>
<td>3,338</td>
<td>1,811</td>
</tr>
<tr>
<td>Low Gap with DSM Option B</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Peak (MW)</td>
<td>1,133</td>
<td>1,222</td>
<td>1,337</td>
<td>1,106</td>
<td>1,271</td>
</tr>
<tr>
<td>Energy (GWh/yr)</td>
<td>4,480</td>
<td>4,511</td>
<td>4,700</td>
<td>4,928</td>
<td>3,607</td>
</tr>
</tbody>
</table>

1 Table 5-10 and Table 5-11 show that an energy gap would remain under either the mid or high gap scenarios. However, Table 5-12 shows that under a low gap scenario, both DSM Options would eliminate the energy gap in the F2013-F2017 timeframe. Under this scenario, incremental DSM savings from DSM Option B would create additional BC Hydro surpluses that would have to be exported in both HLH and LLH, as shown in Figure 5-12. A capacity gap (peak load) occurs in the high gap scenarios for both DSM Options, and not in the mid or low gap scenarios.
5.5.3 Economic Analysis

DSM resources avoid a number of supply-side risks such as First Nations and siting risk, GHG cost risk, commodity fuel risks such as higher natural gas prices, and transmission costs.

To assess the value and benefit of undertaking the DSM Options, three levels of DSM were modelled in portfolios:

- No DSM;
- DSM Option A; and
- DSM Option B.

These DSM Options were modelled in portfolios for the base 11 branch probability tree as shown in Figure 5-1 and the portfolio result summaries are shown in Appendix F16. To compare the DSM Options, the following comparisons were undertaken:
1. DSM Option A versus No DSM; and

2. DSM Option B versus DSM Option A.

3. **DSM Option A versus No DSM**

4. The cost comparison of DSM Option A portfolios to No DSM portfolios is shown in Table 5-13 to Table 5-15.

### Table 5-13 No DSM

<table>
<thead>
<tr>
<th>No DSM Gap</th>
<th>Cost of Thermal</th>
<th>[A] PV of DSM Cost ($M)</th>
<th>[B] PV of Portfolio Cost ($M)</th>
<th>[C] PV of Energy Savings (GWh/year)</th>
<th>[D] PV DSM Cost/Energy Saved ($/MWh)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Gas</td>
<td>GHG</td>
<td>Likelihood</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Low</td>
<td>Low</td>
<td>0.1%</td>
<td>-</td>
<td>12,525</td>
<td>-</td>
</tr>
<tr>
<td>Small</td>
<td>Mid</td>
<td>6.6%</td>
<td>-</td>
<td>12,794</td>
<td>-</td>
</tr>
<tr>
<td></td>
<td>High</td>
<td>3.3%</td>
<td>-</td>
<td>13,691</td>
<td>-</td>
</tr>
<tr>
<td>Low</td>
<td>High</td>
<td>0.5%</td>
<td>-</td>
<td>18,326</td>
<td>-</td>
</tr>
<tr>
<td>Mid</td>
<td>Mid</td>
<td>24.8%</td>
<td>-</td>
<td>18,842</td>
<td>-</td>
</tr>
<tr>
<td></td>
<td>High</td>
<td>10.7%</td>
<td>-</td>
<td>19,289</td>
<td>-</td>
</tr>
<tr>
<td>High</td>
<td>Mid</td>
<td>31.0%</td>
<td>-</td>
<td>20,611</td>
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<tr>
<td></td>
<td>High</td>
<td>13.0%</td>
<td>-</td>
<td>20,878</td>
<td>-</td>
</tr>
<tr>
<td>Large</td>
<td>Low</td>
<td>0.1%</td>
<td>-</td>
<td>23,004</td>
<td>-</td>
</tr>
<tr>
<td></td>
<td>Mid</td>
<td>6.6%</td>
<td>-</td>
<td>23,636</td>
<td>-</td>
</tr>
<tr>
<td></td>
<td>High</td>
<td>3.3%</td>
<td>-</td>
<td>26,806</td>
<td>-</td>
</tr>
<tr>
<td></td>
<td></td>
<td></td>
<td>Weighted Present Value</td>
<td>19,682</td>
<td>-</td>
</tr>
</tbody>
</table>

5. Column A Provides the PV of DSM costs (total resource cost). In the No DSM case, there are no DSM costs.

6. Column B Shows the PV cost of the portfolios for each of the 11 probability tree branches.

7. Column C Provides the PV of electricity supply costs that are avoided by undertaking the DSM. In the No DSM case, there are no DSM energy savings.

8. Column D Shows the levelized energy cost for the DSM energy savings. In the No DSM case, there are no DSM costs.
## Table 5-14  DSM Option A

<table>
<thead>
<tr>
<th>DSM Option A Gap</th>
<th>Cost of Thermal</th>
<th>PV of DSM Cost</th>
<th>PV of Portfolio Cost</th>
<th>PV of Energy Savings</th>
<th>PV DSM Cost/Energy Saved</th>
</tr>
</thead>
<tbody>
<tr>
<td>Low Low</td>
<td>0.1%</td>
<td>4,078</td>
<td>7,809</td>
<td>108,339</td>
<td>38</td>
</tr>
<tr>
<td>Small Mid Mid</td>
<td>6.6%</td>
<td>4,078</td>
<td>7,124</td>
<td>108,339</td>
<td>38</td>
</tr>
<tr>
<td>High High</td>
<td>3.3%</td>
<td>4,078</td>
<td>6,583</td>
<td>108,339</td>
<td>38</td>
</tr>
<tr>
<td>Low Low</td>
<td>0.5%</td>
<td>3,781</td>
<td>11,577</td>
<td>93,342</td>
<td>41</td>
</tr>
<tr>
<td>Small High</td>
<td>24.8%</td>
<td>3,781</td>
<td>11,259</td>
<td>93,342</td>
<td>41</td>
</tr>
<tr>
<td>Mid Mid</td>
<td>10.7%</td>
<td>3,781</td>
<td>11,758</td>
<td>93,342</td>
<td>41</td>
</tr>
<tr>
<td>High High</td>
<td>13.0%</td>
<td>3,781</td>
<td>11,859</td>
<td>93,342</td>
<td>41</td>
</tr>
<tr>
<td>Low Low</td>
<td>0.1%</td>
<td>3,394</td>
<td>17,692</td>
<td>74,848</td>
<td>45</td>
</tr>
<tr>
<td>Large Mid Mid</td>
<td>6.6%</td>
<td>3,394</td>
<td>17,669</td>
<td>74,848</td>
<td>45</td>
</tr>
<tr>
<td>High High</td>
<td>3.3%</td>
<td>3,394</td>
<td>18,490</td>
<td>74,848</td>
<td>45</td>
</tr>
<tr>
<td>Weighted Present Value</td>
<td>3,772</td>
<td>11,857</td>
<td>92,992</td>
<td>41</td>
<td></td>
</tr>
</tbody>
</table>

**Column A** Provides the PV of DSM costs (total resource cost) of DSM Option A.

**Column B** Shows the PV cost of the portfolios for each of the 11 probability tree branches.

**Column C** Provides the PV of energy savings by undertaking the DSM Option A.

**Column D** Shows the levelized energy cost for the DSM energy savings.

## Table 5-15  Relative Cost of DSM Option A as compared to No DSM

<table>
<thead>
<tr>
<th></th>
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<th></th>
<th></th>
<th></th>
</tr>
</thead>
<tbody>
<tr>
<td>Low Low</td>
<td>0.1%</td>
<td>4,078</td>
<td>(4,716)</td>
<td>8,794</td>
<td>108,339</td>
<td>38</td>
<td>81</td>
</tr>
<tr>
<td>Small Mid Mid</td>
<td>6.6%</td>
<td>4,078</td>
<td>(5,670)</td>
<td>9,748</td>
<td>108,339</td>
<td>38</td>
<td>90</td>
</tr>
<tr>
<td>High High</td>
<td>3.3%</td>
<td>4,078</td>
<td>(7,108)</td>
<td>11,186</td>
<td>108,339</td>
<td>38</td>
<td>103</td>
</tr>
<tr>
<td>Low Low</td>
<td>0.5%</td>
<td>3,781</td>
<td>(6,749)</td>
<td>10,530</td>
<td>93,342</td>
<td>41</td>
<td>113</td>
</tr>
<tr>
<td>Mid High</td>
<td>10.7%</td>
<td>3,781</td>
<td>(7,313)</td>
<td>11,094</td>
<td>93,342</td>
<td>41</td>
<td>119</td>
</tr>
<tr>
<td>Mid High</td>
<td>31.0%</td>
<td>3,781</td>
<td>(8,834)</td>
<td>12,165</td>
<td>93,342</td>
<td>41</td>
<td>135</td>
</tr>
<tr>
<td>High High</td>
<td>13.0%</td>
<td>3,781</td>
<td>(8,819)</td>
<td>12,600</td>
<td>93,342</td>
<td>41</td>
<td>135</td>
</tr>
<tr>
<td>Low Low</td>
<td>0.1%</td>
<td>3,394</td>
<td>(5,312)</td>
<td>8,706</td>
<td>74,848</td>
<td>45</td>
<td>116</td>
</tr>
<tr>
<td>Large Mid Mid</td>
<td>6.6%</td>
<td>3,394</td>
<td>(5,967)</td>
<td>9,361</td>
<td>74,848</td>
<td>45</td>
<td>125</td>
</tr>
<tr>
<td>High High</td>
<td>3.3%</td>
<td>3,394</td>
<td>(8,316)</td>
<td>11,710</td>
<td>74,848</td>
<td>45</td>
<td>156</td>
</tr>
<tr>
<td>Weighted Present Value</td>
<td>3,772</td>
<td>(7,825)</td>
<td>11,597</td>
<td>92,992</td>
<td>41</td>
<td>125</td>
<td></td>
</tr>
</tbody>
</table>

**Column A** Provides the PV of DSM Option A costs (total resource cost) versus No DSM as modelled in the portfolios.

**Column B** Shows the PV cost differential between the DSM Option A portfolios and the No DSM portfolios for each of the 11 probability tree branches.

**Column C** Provides the PV of electricity supply costs that are avoided by undertaking DSM Option A. This is calculated as column [A] - column [B].

**Column D** Shows the PV of the GWh/year of energy savings acquired in the DSM Option A portfolios to allow the levelized UEC calculations in E and F.

1. Table 5-15 shows that the DSM Option A is substantially lower cost than electricity supply.
2. Specifically:
• DSM Option A reduces the cost of closing the gap between $4.7 billion and $8.8 billion in PV terms relative to a no DSM scenario, with a weighted average saving of $7.8 billion;

• The UEC of DSM Option A ranges from $38/MWh to $45/MWh, depending on the level of energy savings achieved. This is substantially less than the unit cost of additional IPP supply, with unit costs ranging from $81/MWh to $156/MWh, depending on the size of the gap and the marginal cost of IPP resources.

The relative cost of DSM and electricity supply is further demonstrated in Figure 5-13.

The chart shows how the unit cost of electricity supply decreases as the gap decreases and natural gas and GHG prices decrease. In all scenarios, the cost of DSM Option A remains significantly lower than electricity supply.

**DSM Option B versus DSM Option A**

Comparing DSM Option B versus DSM Option A tests the cost of incremental DSM savings and the results are shown in Table 5-16.
### Table 5-16 Relative Value of DSM Option B as compared to DSM Option A

<table>
<thead>
<tr>
<th>DSM Option B - DSM Option A Gap Cost of Thermal</th>
<th>[A] PV of DSM Cost ($M)</th>
<th>[B] PV of Portfolio Cost ($M)</th>
<th>[C] PV of Supply Side Avoided Cost ($M)</th>
<th>[D] PV of Energy Savings (GWh/year)</th>
<th>[E] PV DSM Cost/Energy Saved ($/MWh)</th>
<th>[F] PV Supply Side Avoided Cost ($/MWh)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Gas</td>
<td>GHG</td>
<td>Likelihood</td>
<td>PV of DSM Cost ($M)</td>
<td>PV of Portfolio Cost ($M)</td>
<td>PV of Supply Side Avoided Cost ($M)</td>
<td>PV of Energy Savings (GWh/year)</td>
</tr>
<tr>
<td>Small</td>
<td>Low</td>
<td>Low</td>
<td>0.1%</td>
<td>752</td>
<td>43</td>
<td>709</td>
</tr>
<tr>
<td>Mid</td>
<td>Mid</td>
<td>6.6%</td>
<td>752 (246)</td>
<td>998</td>
<td>19,722</td>
<td>38</td>
</tr>
<tr>
<td>High</td>
<td>High</td>
<td>3.3%</td>
<td>752 (645)</td>
<td>1,397</td>
<td>19,722</td>
<td>38</td>
</tr>
<tr>
<td>Mid</td>
<td>Low</td>
<td>0.5%</td>
<td>691 (410)</td>
<td>1,101</td>
<td>13,400</td>
<td>52</td>
</tr>
<tr>
<td>High</td>
<td>High</td>
<td>31.0%</td>
<td>691 (785)</td>
<td>1,471</td>
<td>13,400</td>
<td>52</td>
</tr>
<tr>
<td>High</td>
<td>Low</td>
<td>0.1%</td>
<td>585 (1,260)</td>
<td>1,845</td>
<td>12,423</td>
<td>47</td>
</tr>
<tr>
<td>Mid</td>
<td>Mid</td>
<td>6.6%</td>
<td>585 (1,293)</td>
<td>1,878</td>
<td>12,423</td>
<td>47</td>
</tr>
<tr>
<td>High</td>
<td>High</td>
<td>3.3%</td>
<td>585 (1,211)</td>
<td>1,796</td>
<td>12,423</td>
<td>47</td>
</tr>
</tbody>
</table>

#### Weighted Present Value

- **Low Low 0.1%**: 687 (709), 1,396, 13,935, 50, 103

---

1. Column A: Provides the PV of DSM Option B costs (total resource cost) versus DSM Option A as modelled in the portfolios.
2. Column B: Shows the PV cost differential between the DSM Option B portfolios and DSM Option A portfolios for each of the 11 probability tree branches.
3. Column C: Provides the PV of additional electricity supply costs that are avoided by undertaking DSM Option B as compared to DSM Option A. This is calculated as column [A] - column [B].
4. Column D: Shows the PV of the GWh/year of energy savings acquired in the DSM Option A portfolios to allow the levelized UEC calculations in E and F.

The results show that the incremental DSM savings from DSM Option B would continue to show a net PV benefit under most scenarios.

- Under a mid gap scenario, DSM Option B would reduce the cost of closing the gap by $400 million to $800 million in PV terms. The cost of incremental DSM would be $52/MWh and displaces incremental supply resources in the $82-110/MWh range.
- Under a high gap scenario, the PV benefit of DSM Option B over DSM Option A exceeds $1.2 billion. The IPP displaced costs now range up to $151/MWh.
- However, under a low gap scenario, DSM Option B would provide more energy savings than required to close the gap. In this event, BC Hydro would export a significant volume of energy into the markets (refer back to Figure 5-12 to see the volumes of electricity that would be exported). Under a low gap and low market price scenario, the incremental DSM costs would outweigh the benefits, resulting in a net cost of $43 million in PV terms.
The relative cost of the incremental DSM savings associated with DSM Option B as compared to the displaced electricity supply of DSM Option A is further demonstrated in Figure 5-14.

The analysis demonstrates that the incremental savings from DSM Option B is low cost from a total resource cost basis in most cases. While the margins are decreasing, they remain positive. However, the volumes of DSM savings (capacity and energy) could exceed BC Hydro’s need for the next 15-20 years and, under certain market cases, may result in a net cost.

### 5.5.4 DSM Deliverability Risk

Like other resources, DSM involves deliverability risks. Deliverability risk is the risk that the DSM Options do not deliver the projected electricity savings within the specified time frame. Assessment of deliverability risk focused on the ability to achieve the forecast DSM savings and the implications of not achieving these savings. This included consideration of

- The expected variability of the resource;
The degree of reliance on the resource (e.g., how much of the gap is met by the resource); and

The proven success of similar programs either here or in other jurisdictions.

The initial variability assessment of DSM was undertaken through the Risk Framework and probability elicitation process. This work has shown that the savings spread between low and high under DSM Option B is larger than under DSM Option A.

<table>
<thead>
<tr>
<th>Table 5-17 Low, Mid, and High Ranges for DSM Energy Savings</th>
</tr>
</thead>
<tbody>
<tr>
<td><strong>Probability</strong></td>
</tr>
<tr>
<td>DSM Option A</td>
</tr>
<tr>
<td>GWh/yr savings, 2020</td>
</tr>
<tr>
<td>DSM Option B</td>
</tr>
<tr>
<td>GWh/yr savings, 2020</td>
</tr>
</tbody>
</table>

Note: These values include distribution and transmission loss savings.

As addressed in Appendix F14, subjective assessments of uncertainty are subject to a well-known bias to under-estimate uncertainty and while the subjective assessments for this LTAP were designed and carried out with this in mind, the pervasiveness of this bias warrants caution in concluding whether the assessments accurately reflect the full spread of uncertainty. In addition, application of the Risk Framework to DSM was a first-time effort that involved eliciting probability assessments regarding DSM tools that were new to BC Hydro DSM planning, such as codes and standards and conservation rate structures, and programs that involved higher levels of effort than previous years. As such, the Risk Framework may not have identified and captured all drivers of DSM performance risk and correlations between drivers.

In terms of degree of reliance, DSM Option A would meet 78 per cent of the energy gap in F2020 while DSM Option B would meet 92 per cent of the energy gap in F2020.

With respect to the capacity savings, there are similar uncertainties. In addition to the range of capacity savings, Table 5-18 presents the annual average growth in DSM demand savings (the speed at which the DSM demand savings are being acquired). It also shows
the equivalent supply side saving that this corresponds to by reflecting the saved 14 per cent capacity reserve.

Table 5-18  Low, Mid, and High Ranges for DSM Capacity Savings

<table>
<thead>
<tr>
<th>Probability</th>
<th>Low (Reduction From Mid)</th>
<th>Mid</th>
<th>High (Increase From Mid)</th>
<th>Average Annual Increase in Demand Saving</th>
<th>Supply Equivalent Average Annual Increase in</th>
</tr>
</thead>
<tbody>
<tr>
<td>DSM Option A</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>MW savings, F2020</td>
<td>(210)</td>
<td>1,850</td>
<td>250</td>
<td>160</td>
<td>190</td>
</tr>
<tr>
<td>DSM Option B</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>MW savings, F2020</td>
<td>(290)</td>
<td>2,200</td>
<td>340</td>
<td>190</td>
<td>220</td>
</tr>
</tbody>
</table>

Note: These values include distribution and transmission loss savings.

The above DSM capacity savings, when measured in capacity MW (including planning reserve), show that both DSM Options provide more incremental savings each year than the size of one Burrard unit. DSM Option B provides nearly the same amount of capacity savings every two years as one Mica unit would provide.

As compared to the growth in the Integrated Peak demand to F2021 of 1,675 MW (Table 2-4), the DSM Option A and Option B peak demand savings represent 111 per cent and 138 per cent respectively for that reporting year. This results in a decline in the net Integrated System peak demand in F2021 as compared to F2008 in both the DSM Option A and DSM Option B.

Given this degree of energy and capacity reliance, the potential consequence of under delivery in either timing or volume could be substantial. This is addressed in the CRPs in section 6.4.2. While the DSM Options appear very attractive from a cost perspective, actual performance will need to be monitored very carefully and contingency plans must be in place.

BC Hydro also looked to resource diversity and jurisdictional assessments in considering whether or not to proceed with DSM Option A or Option B. As set out above, DSM Option B
would meet 92 per cent of the energy gap in F2020. Option B would also result in BC Hydro meeting 106 per cent of its incremental energy load and 138 per cent of the growth in peak demand between F2008 and F2021 through DSM.

BC Hydro compared Option A and Option B to eleven U.S. jurisdictions/utilities located in the U.S. Northeast, the U.S. Pacific Northwest and California. In addition, three comparable Canadian jurisdictions were reviewed. DSM plans in these jurisdictions are multi-year plans that are at various stages of implementation. Table 5-19 compares the average annual DSM savings as a percentage of sales, a measure of a DSM plan’s aggressiveness across these utilities and jurisdictions. Figures are presented for different portions of BC Hydro’s DSM Options A and B to match available data from other jurisdictions. These figures may not reflect the full extent of energy conservation activity in those jurisdictions. It should also be noted that there are a number of U.S. states which have targeted lower amounts of DSM than the BC Hydro DSM Plan which are not listed in Table 5-19. As seen in Table 5-19 only New York and New Jersey, both high cost jurisdictions, are more aggressive than BC Hydro’s Option B.
Table 5-19: Average Annual DSM Energy Savings as a Percentage of Sales

<table>
<thead>
<tr>
<th>Programs</th>
<th>Programs + Rate Structures</th>
<th>Programs + Codes and Standards</th>
<th>Programs + Rate Structures + Codes and Standards</th>
</tr>
</thead>
<tbody>
<tr>
<td>New York 82</td>
<td>1.5</td>
<td>2.0</td>
<td></td>
</tr>
<tr>
<td>New Jersey (proposed) 83</td>
<td>1.5</td>
<td>2.0</td>
<td></td>
</tr>
<tr>
<td>BC Hydro – Option B</td>
<td>1.1</td>
<td>1.5</td>
<td>1.7</td>
</tr>
<tr>
<td>Efficiency Vermont</td>
<td></td>
<td>1.6</td>
<td></td>
</tr>
<tr>
<td>San Diego Gas &amp; Electric</td>
<td></td>
<td>1.4</td>
<td></td>
</tr>
<tr>
<td>Wisconsin (proposed) 84</td>
<td></td>
<td>1.4</td>
<td></td>
</tr>
<tr>
<td>Portland Gas &amp; Electric 85</td>
<td>1.0</td>
<td></td>
<td></td>
</tr>
<tr>
<td>BC Hydro – Option A</td>
<td>0.8</td>
<td>1.1</td>
<td>1.3</td>
</tr>
<tr>
<td>Southern California Edison</td>
<td></td>
<td>1.3</td>
<td></td>
</tr>
<tr>
<td>Pacific Gas &amp; Electric</td>
<td></td>
<td>1.2</td>
<td></td>
</tr>
<tr>
<td>Puget Sound Energy</td>
<td></td>
<td>0.9</td>
<td></td>
</tr>
<tr>
<td>Avista</td>
<td></td>
<td>0.8</td>
<td></td>
</tr>
<tr>
<td>PacifiCorp</td>
<td></td>
<td>0.7</td>
<td></td>
</tr>
<tr>
<td>Fortis BC</td>
<td>0.5</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Manitoba Hydro</td>
<td>0.4</td>
<td>0.6</td>
<td></td>
</tr>
<tr>
<td>Hydro Quebec (proposed)</td>
<td></td>
<td></td>
<td>0.6</td>
</tr>
</tbody>
</table>

1 5.5.5 Conclusions

The DSM resource options avoid a number of supply-side risks such as First Nations and siting risk, GHG cost risk, commodity fuel risks such as higher natural gas prices, and transmission costs. This adds to its value as a key resource to in BC Hydro’s acquisition plans.

Based upon DSM’s low cost, the uncertainties and costs of supply side options, and in consideration of the degree of reliance on DSM programs, BC Hydro concludes that it should set a plan in line with DSM Option A, and that this significant challenge should be the extent of the reliance on DSM savings at this point in time.

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82 New York State Energy Research & Development Authority
83 New Jersey Energy Master Plan
84 Wisconsin Governor’s Task Force on Global Warming
85 The DSM numbers for Portland Gas & Electric include both the utility’s DSM savings and the savings resulting from the Energy Trust of Oregon.
5.6 **Acquisitions (Call for Power)**

A key issue for the 2008 LTAP: is an acquisition process necessary before the completion of the next LTAP; and if so, what size, type and timing of new supply resources should be targeted.

The 2008 LTAP identifies a need for additional supply resources under expected conditions after reflecting the implementation of DSM Option A. There is considerable uncertainty as to the size of the gap even through F2017. BC Hydro will be looking to the IPP community through acquisition processes to fill all or substantially all of any near to mid term gap. Key uncertainties that need to be addressed through portfolio planning include:

- Size of the gap, including DSM and past acquisition process delivery risk;
- Natural gas prices;
- Possible future impacts of GHG legislation or carbon taxes; and
- Costs of the available clean supply sources.

To address the issues in light of the above mentioned uncertainties, the analysis focuses on the risks that would result from a decision to proceed with an acquisition process in the short term (next two years). The risks include:

- **Volume**: The amount of electricity ultimately acquired would be greater than or less than that actually required (either direction is a risk). This could arise because the load growth is different than that expected, the DSM is more or less successful than expected, the supply attrition from past calls or this new acquisition was materially different than expected.

- **Cost**: The cost incurred by BC Hydro for the electricity acquired from a new acquisition is higher than it would have been if a different acquisition mix decision had been made. This could arise from the future costs of natural gas are different than expected, GHG or carbon tax regulations are more or less than expected, the costs of any new clean supply that is acquired is materially higher than expected. With respect to the 2008 LTAP, this is primarily a clean vs. gas risk comparison.

5.6.1 **Analysis**

Three types of analysis were used to evaluate the issue as described:
• Deterministic supply/demand gap analysis to identify the size of the gap that may exist;
• Optimum sequence development based on perfect foresight provides a view as to what
  the resource selection would be if the world turned out exactly as planned for each
  scenario in the probability tree; and
• Call Commitment analysis based on a certain call decision being made in the near term
  such that EPA awards could be made before the end of 2009, and the world unfolds
  differently than planned. For this, a specific near-term acquisition decision is tested
  against each of the scenarios in the probability tree.

5.6.2 Supply Adequacy Analysis

The analysis starts from the basic input assumption regarding the load/resource gap with
existing and committed resources plus DSM Option A. Note that this includes Burrard at
900 MW/3000 GWh/year. Based on this, BC Hydro forecasts the Load/Resource Gaps as
shown in Table 5-20 to Table 5-22. A positive number denotes a surplus while a negative
denotes a deficit. Any deficits would have to be met by some new resource if the respective
gap were to occur. Peak refers to the BC Hydro system peak demand in MW and Energy
refers to the BC Hydro annual energy demand in GWh/year.

If the Mid Gap were to occur, the following is the Load/Resource balance:

Table 5-20 Mid Gap Load/Resource Gap with
Existent and Committed Resources plus
DSM Option A

<table>
<thead>
<tr>
<th></th>
<th></th>
<th></th>
<th></th>
<th></th>
<th></th>
</tr>
</thead>
<tbody>
<tr>
<td>Peak (MW)</td>
<td>382</td>
<td>356</td>
<td>358</td>
<td>37</td>
<td>115</td>
</tr>
<tr>
<td>Energy (GWh/yr)</td>
<td>339</td>
<td>-352</td>
<td>-905</td>
<td>-1,315</td>
<td>-3,258</td>
</tr>
</tbody>
</table>

If the High Gap case occurs, there is a deficit of capacity and energy:

Table 5-21 High Gap Load/Resource Gap with
Existent and Committed Resources plus
DSM Option A

<table>
<thead>
<tr>
<th></th>
<th></th>
<th></th>
<th></th>
<th></th>
<th></th>
</tr>
</thead>
<tbody>
<tr>
<td>Peak (MW)</td>
<td>-180</td>
<td>-262</td>
<td>-319</td>
<td>-697</td>
<td>-671</td>
</tr>
<tr>
<td>Energy (GWh/yr)</td>
<td>-3,085</td>
<td>-4,175</td>
<td>-5,156</td>
<td>-5,956</td>
<td>-8,294</td>
</tr>
</tbody>
</table>

If the Low Gap case occurs, there is a surplus:

---

86 The following load/resource gap analysis is based on the same gap analysis provided in Chapter 2.
Table 5-22  Low Gap Load/Resource Gap with Existing and Committed Resources plus DSM Option A

<table>
<thead>
<tr>
<th></th>
<th></th>
<th></th>
<th></th>
<th></th>
</tr>
</thead>
<tbody>
<tr>
<td>Peak (MW)</td>
<td>947</td>
<td>981</td>
<td>1,047</td>
<td>791</td>
</tr>
<tr>
<td>Energy (GWh/yr)</td>
<td>3,730</td>
<td>3,432</td>
<td>3,320</td>
<td>3,338</td>
</tr>
</tbody>
</table>

For an acquisition process that is initiated following the 2008 LTAP, the award of EPAs could occur near the end of 2009. This would allow a maximum window for a proponent of approximately six years if all projects were to be available no later than 2016.

If BC Hydro did not include an acquisition process in the 2008 LTAP, and for an acquisition to be tested with the full context of a current LTAP, that process would likely next occur in 2011 with a possible BCUC decision date in 2012. If the acquisition process were delayed until that time, it would make it very difficult to acquire the additional resources necessary to meet the mid or high gaps before 2016. Based on BC Hydro’s experience with the F2006 Call, a minimum of five to six years is required from initial call design to the achievement of significant energy deliveries under new power acquisition processes.

Any risks of additional attrition of IPP projects from past acquisition processes or of not being able to obtain the amount of DSM (both volume and timing) as planned would increase the amount of supply that would have to be made up from other processes.

5.6.3 Optimum Sequence Analysis

The optimum sequence of resource additions was developed for each of the base portfolios. These sequences identify the types of resources that would be selected from an economic perspective if the specific scenario being tested (for example small gap, low thermal (gas and GHG)) was predicted to occur and then actually occurred. That is, there is perfect foresight and perfect economic decision making.

The main comparison being presented in this analysis is the relative amount of clean or renewable resources (Clean) vs. resources fuelled by natural gas (Thermal). The new resources that are selected for two time slices for 2016 and 2027 are presented in the following probability tree.
Table 5-23 Results of the 11 Base Scenarios showing the amount of Thermal and Clean Resources

<table>
<thead>
<tr>
<th>Gap</th>
<th>Cost of Thermal</th>
<th>Dependable Capacity</th>
<th>Firm Energy</th>
<th>Dependable Capacity</th>
<th>Firm Energy</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>Gas GHG Likelihood</td>
<td>Thermal MW Clean MW</td>
<td>Thermal GWh Clean GWh</td>
<td>Thermal MW Clean MW</td>
<td>Thermal GWh Clean GWh</td>
</tr>
<tr>
<td>Small</td>
<td>Low Low 0.1%</td>
<td>236 100</td>
<td>1,448 801</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Mid Mid 6.6%</td>
<td>202 227</td>
<td>2,106 237</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>High High 3.3%</td>
<td>1,226 227</td>
<td>2,387 237</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Mid Low 0.5%</td>
<td>479 137</td>
<td>2,399 1,226</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Mid Mid 24.8%</td>
<td>479 188</td>
<td>2,939 1,637</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>High Mid 31.0%</td>
<td>479 188</td>
<td>2,939 1,637</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>High High 10.7%</td>
<td>319 188</td>
<td>3,940 1,637</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Large</td>
<td>Low Low 0.1%</td>
<td>577 418</td>
<td>3,094 5,386</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Mid Mid 6.6%</td>
<td>577 418</td>
<td>3,094 5,386</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>High High 3.3%</td>
<td>577 418</td>
<td>3,094 5,386</td>
<td></td>
<td></td>
<td></td>
</tr>
</tbody>
</table>

Note: The large gap, high gas scenario includes Mica Units 5 and 6 in addition to the Clean and Thermal resources identified in the Table. The units were added in 2016 and 2022.

The above analysis identifies a general picture of what may be required over the coming 20 years and the impact of what would occur under varying scenarios of load growth, DSM success, electricity and natural gas market prices and GHG Offset costs. Table 5-23 shows that under the 11 scenarios, resources are required and/or are economically selected by 2016 in all cases except the low gap, mid and low gas/GHG scenarios. For the five mid gap scenarios, an average of 4,200 GWh of firm energy resources is selected in the simulations to meet the gap of 3,000 to 3,500 GWh identified in Table 5-20.

The probability tree analysis also shows that clean resources are selected in all situations at some time through the planning horizon, while gas-fired generation is being selected only in the low to mid thermal (natural gas and GHG offset) cost scenarios, as well as in the high gap scenarios. As can be seen in the mid-gap cases, the most probable scenario is the high gas/mid GHG case and thermal was not picked up. This demonstrates that if the world unfolded as per our most probable scenario, gas would not be economic.

The relative economics of the 11 portfolios are presented in Table 5-24. This table presents the economics first without including any possible revenue from future REC sales, followed by the economics assuming REC sales revenue based on the low, mid and high REC price scenarios that were identified in section 4.5.
Table 5-24  Present Value of Costs of the Base 11 Scenarios including REC Sales

<table>
<thead>
<tr>
<th>Gap</th>
<th>Cost of Thermal</th>
<th>Present Value of Portfolios including Scenarios of RPS Sales Revenue</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>Gas</td>
<td>GHG</td>
</tr>
<tr>
<td>Small</td>
<td>Low</td>
<td>Low</td>
</tr>
<tr>
<td></td>
<td>Mid</td>
<td>Mid</td>
</tr>
<tr>
<td></td>
<td>High</td>
<td>High</td>
</tr>
<tr>
<td>Mid</td>
<td>Low</td>
<td>Low</td>
</tr>
<tr>
<td></td>
<td>Mid</td>
<td>Mid</td>
</tr>
<tr>
<td></td>
<td>High</td>
<td>Mid</td>
</tr>
<tr>
<td></td>
<td>High</td>
<td>High</td>
</tr>
<tr>
<td>Large</td>
<td>Low</td>
<td>Low</td>
</tr>
<tr>
<td></td>
<td>Mid</td>
<td>Mid</td>
</tr>
<tr>
<td></td>
<td>High</td>
<td>High</td>
</tr>
</tbody>
</table>

Weighted Present Value 11,857  11,443  11,200  10,958

1. The results generally show that the portfolios in the small gap become less expensive as the thermal cost rises. This is because the portfolios have surplus energy and are exporting.
2. Increased thermal cost also reflects increased base electricity market prices and thus higher revenue. As the REC sales price rises, the portfolio costs drop reflecting the impact of the additional revenue.
3. For the mid gap cases, the export revenue with higher thermal costs is offset with the overall increased costs of new supply as gas prices rise. However, once REC market prices are reflected, the value of exports increases more rapidly in the high thermal cost scenarios than in the low thermal cost scenarios because of the higher base electricity market price.
4. In the high gap cases, there is significant thermal generation in all portfolios. Therefore the costs rise as the thermal costs rise.

5.6.4 Call Commitment Analysis

To assess the relative value of, and risks to, a near-term acquisition process, a risk analysis was completed identifying the impacts of acquisitions that would result in EPAs for energy to be on stream between 2012 and 2016. The analysis identifies two distinct blocks of resources that are assumed to be acquired through an acquisition process undertaken in the
2008/2009 time period. The first block (Clean Call Block) is made up exclusively of B.C. clean or renewable resources and represents the results of a Clean Call for Power, while the second block (Open Call Block) is a mix of gas-fired generation and B.C. clean or renewable resources and represents the results of an Open Call for Power. The two Call Blocks are alternative (not cumulative) strategies. The Clean Call Block is representative of what would be acquired by 2016 if the optimum selection criteria based on perfect foresight were based on the mid gap and high gas (mid or high GHG) scenarios. The Open Call Block would be representative of what would be acquired by 2016 if the optimum selection criteria based on perfect foresight were based on the mid gap and mid gas and mid GHG scenario.

The results of resources selected for delivery by 2016 are shown in Table 5-25.

<table>
<thead>
<tr>
<th>Scenario</th>
<th>Dependable Capacity (MW)</th>
<th>Firm Energy (GWh)</th>
<th>Total</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>Thermal</td>
<td>Clean</td>
<td>Thermal</td>
</tr>
<tr>
<td>Clean Call Block</td>
<td>0</td>
<td>319</td>
<td>0</td>
</tr>
<tr>
<td>Open Call Block</td>
<td>479</td>
<td>188</td>
<td>2939</td>
</tr>
</tbody>
</table>

For each near term bundle selected above, the benefits and costs of having selected these initial resources was tested through a range of possible future conditions as identified in the probability framework. That is, each Call Block was fixed in the SO as if contracted. Simulations of each of the 11 scenarios in the probability tree were then completed to test the robustness of each of the two Call Blocks when faced with the range of possible future scenarios.
### Table 5-26  Results of the Commitment Analysis for the Clean Call Block showing the amount of Thermal and Clean Resources

<table>
<thead>
<tr>
<th>Gap</th>
<th>Cost of Thermal</th>
<th>2012-2016</th>
<th>2012-2027</th>
</tr>
</thead>
<tbody>
<tr>
<td>Low Low</td>
<td>0.1%</td>
<td>- 319</td>
<td>- 3,940</td>
</tr>
<tr>
<td>Small</td>
<td>Mid High 6.6%</td>
<td>- 319</td>
<td>- 3,940</td>
</tr>
<tr>
<td>High High</td>
<td>Low Low 3.3%</td>
<td>- 319</td>
<td>- 3,940</td>
</tr>
<tr>
<td>Low Low</td>
<td>0.5%</td>
<td>- 319</td>
<td>- 3,940</td>
</tr>
<tr>
<td>Low Low</td>
<td>Mid High 6.6%</td>
<td>- 319</td>
<td>- 3,940</td>
</tr>
<tr>
<td>High High</td>
<td>Low Low 3.3%</td>
<td>- 319</td>
<td>- 3,940</td>
</tr>
<tr>
<td>Low Low</td>
<td>0.1%</td>
<td>958</td>
<td>319</td>
</tr>
<tr>
<td>Low Low</td>
<td>Mid High 6.6%</td>
<td>715</td>
<td>319</td>
</tr>
<tr>
<td>High High</td>
<td>Mid High 3.3%</td>
<td>955</td>
<td>319</td>
</tr>
<tr>
<td>Low Low</td>
<td>958</td>
<td>237</td>
<td>5,878</td>
</tr>
<tr>
<td>Large</td>
<td>Mid High 6.6%</td>
<td>956</td>
<td>241</td>
</tr>
<tr>
<td>Large</td>
<td>High High 3.3%</td>
<td>479</td>
<td>391</td>
</tr>
</tbody>
</table>

Note: The large gap, high gas scenario includes Mica Unit 5 in addition to the Clean and Thermal resources identified in the Table. The unit was added in 2016.

### Table 5-27  Results of the Commitment Analysis for the Open Call Block showing the amount of Thermal and Clean Resources

<table>
<thead>
<tr>
<th>Gap</th>
<th>Cost of Thermal</th>
<th>2012-2016</th>
<th>2012-2027</th>
</tr>
</thead>
<tbody>
<tr>
<td>Low Low</td>
<td>0.1%</td>
<td>479</td>
<td>188</td>
</tr>
<tr>
<td>Small</td>
<td>Mid High 6.6%</td>
<td>479</td>
<td>188</td>
</tr>
<tr>
<td>High High</td>
<td>Low Low 3.3%</td>
<td>479</td>
<td>188</td>
</tr>
<tr>
<td>Low Low</td>
<td>0.5%</td>
<td>479</td>
<td>188</td>
</tr>
<tr>
<td>Low Low</td>
<td>Mid High 6.6%</td>
<td>479</td>
<td>188</td>
</tr>
<tr>
<td>High High</td>
<td>Low Low 3.3%</td>
<td>479</td>
<td>188</td>
</tr>
<tr>
<td>Low Low</td>
<td>0.1%</td>
<td>958</td>
<td>237</td>
</tr>
<tr>
<td>Low Low</td>
<td>Mid High 6.6%</td>
<td>956</td>
<td>241</td>
</tr>
<tr>
<td>High High</td>
<td>Mid High 3.3%</td>
<td>479</td>
<td>391</td>
</tr>
</tbody>
</table>

Note: The large gap, high gas scenario includes Mica Unit 5 in addition to the Clean and Thermal resources identified in the Table. The unit was added in 2020.

1. In each of these scenarios, the impact of having selected the Call Blocks was tested against future scenarios in the following way:

2. The next time that new resources could be committed to after the initial Call Blocks would have an earliest in-service date of 2015. This restriction generally impacts high gap scenarios;
None of the initial Call Blocks could be terminated early, reflecting the impact of executing EPAs with IPPs. This restriction generally impacts the low gap scenarios; as is the case in normal operations, the market is relied on in the period through to 2015 to make up any operational shortfalls or surpluses in dependable capacity and firm energy; and a sensitivity analysis was performed in which any surplus clean energy was assumed to be sold to a REC market for a range of premiums to the Mid-C market price. The results of the analyses are shown in tables Table 5-28, to Table 5-31.

Table 5-28 Difference in Present Value of Costs between the Clean Call Block and the Open Call Block (No REC Sales)

<table>
<thead>
<tr>
<th>Gap</th>
<th>Cost of Thermal</th>
<th>PV of Portfolios ($M)</th>
<th>Clean Call Block</th>
<th>Open Call Block</th>
<th>Difference</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>Gas</td>
<td>GHG</td>
<td>Likelihood</td>
<td>Clean Call</td>
<td>Open Call</td>
</tr>
<tr>
<td>Small</td>
<td>Low</td>
<td>Low</td>
<td>0.1%</td>
<td>9,535</td>
<td>9,353</td>
</tr>
<tr>
<td></td>
<td>Mid</td>
<td>Mid</td>
<td>6.6%</td>
<td>8,292</td>
<td>8,306</td>
</tr>
<tr>
<td></td>
<td>High</td>
<td>High</td>
<td>3.3%</td>
<td>7,040</td>
<td>7,912</td>
</tr>
<tr>
<td>Mid</td>
<td>Low</td>
<td>Low</td>
<td>0.5%</td>
<td>11,976</td>
<td>11,621</td>
</tr>
<tr>
<td></td>
<td>Mid</td>
<td>Mid</td>
<td>24.8%</td>
<td>11,738</td>
<td>11,528</td>
</tr>
<tr>
<td></td>
<td>High</td>
<td>Mid</td>
<td>10.7%</td>
<td>11,879</td>
<td>11,766</td>
</tr>
<tr>
<td></td>
<td>High</td>
<td>High</td>
<td>31.0%</td>
<td>11,777</td>
<td>12,326</td>
</tr>
<tr>
<td></td>
<td>High</td>
<td>High</td>
<td>13.0%</td>
<td>11,854</td>
<td>12,513</td>
</tr>
<tr>
<td>Large</td>
<td>Low</td>
<td>Low</td>
<td>0.1%</td>
<td>15,958</td>
<td>15,683</td>
</tr>
<tr>
<td></td>
<td>Mid</td>
<td>Mid</td>
<td>6.6%</td>
<td>16,248</td>
<td>16,023</td>
</tr>
<tr>
<td></td>
<td>High</td>
<td>High</td>
<td>3.3%</td>
<td>17,847</td>
<td>17,833</td>
</tr>
</tbody>
</table>

Weighted Present Value 11,900 12,104 (204)

Table 5-28 demonstrates that the impacts of selecting gas-fired generation early with the natural gas prices ending up being higher, associated with the relatively higher probability that gas prices tend toward the higher prices, outweigh the benefits of potentially lower cost gas that is much less likely to occur.
### Table 5-29 Present Value of Costs of the Clean Call Block Scenarios including REC Sales

#### Call Commitment Analysis: Clean Call Block

<table>
<thead>
<tr>
<th>Gas</th>
<th>GHG</th>
<th>Likelihood</th>
<th>None</th>
<th>Low</th>
<th>Mid</th>
<th>High</th>
</tr>
</thead>
<tbody>
<tr>
<td>Low</td>
<td>Low</td>
<td>0.1%</td>
<td>9,535</td>
<td>8,400</td>
<td>7,701</td>
<td>7,002</td>
</tr>
<tr>
<td>Mid</td>
<td>Mid</td>
<td>6.6%</td>
<td>8,292</td>
<td>7,161</td>
<td>6,465</td>
<td>5,769</td>
</tr>
<tr>
<td>High</td>
<td>High</td>
<td>3.3%</td>
<td>7,040</td>
<td>5,925</td>
<td>5,239</td>
<td>4,553</td>
</tr>
</tbody>
</table>

#### Present Value of Portfolios including Scenarios of RPS Sales Revenue

<table>
<thead>
<tr>
<th>Gas</th>
<th>GHG</th>
<th>Likelihood</th>
<th>None</th>
<th>Low</th>
<th>Mid</th>
<th>High</th>
</tr>
</thead>
<tbody>
<tr>
<td>Low</td>
<td>Low</td>
<td>0.5%</td>
<td>11,976</td>
<td>11,643</td>
<td>11,452</td>
<td>11,261</td>
</tr>
<tr>
<td>Mid</td>
<td>Mid</td>
<td>24.8%</td>
<td>11,738</td>
<td>11,388</td>
<td>11,188</td>
<td>10,987</td>
</tr>
<tr>
<td>High</td>
<td>High</td>
<td>10.7%</td>
<td>11,879</td>
<td>11,488</td>
<td>11,263</td>
<td>11,037</td>
</tr>
<tr>
<td>Low</td>
<td>Low</td>
<td>0.5%</td>
<td>11,854</td>
<td>11,437</td>
<td>11,198</td>
<td>10,959</td>
</tr>
<tr>
<td>Mid</td>
<td>Mid</td>
<td>24.8%</td>
<td>11,777</td>
<td>11,360</td>
<td>11,121</td>
<td>10,882</td>
</tr>
<tr>
<td>High</td>
<td>High</td>
<td>10.7%</td>
<td>11,847</td>
<td>11,432</td>
<td>11,260</td>
<td>11,062</td>
</tr>
<tr>
<td>Large</td>
<td>Mid</td>
<td>6.6%</td>
<td>16,248</td>
<td>15,865</td>
<td>15,645</td>
<td>15,425</td>
</tr>
<tr>
<td>High</td>
<td>High</td>
<td>3.3%</td>
<td>17,847</td>
<td>17,315</td>
<td>17,008</td>
<td>16,701</td>
</tr>
</tbody>
</table>

**Weighted Present Value**

<table>
<thead>
<tr>
<th></th>
<th>11,900</th>
<th>11,431</th>
<th>11,157</th>
<th>10,883</th>
</tr>
</thead>
</table>

### Table 5-30 Present Value of Costs of the Open Call Block Scenarios including REC Sales

#### Call Commitment Analysis: Open Call Block

<table>
<thead>
<tr>
<th>Gas</th>
<th>GHG</th>
<th>Likelihood</th>
<th>None</th>
<th>Low</th>
<th>Mid</th>
<th>High</th>
</tr>
</thead>
<tbody>
<tr>
<td>Low</td>
<td>Low</td>
<td>0.1%</td>
<td>9,353</td>
<td>8,243</td>
<td>7,559</td>
<td>6,875</td>
</tr>
<tr>
<td>Mid</td>
<td>Mid</td>
<td>6.6%</td>
<td>8,306</td>
<td>7,200</td>
<td>6,520</td>
<td>5,840</td>
</tr>
<tr>
<td>High</td>
<td>High</td>
<td>3.3%</td>
<td>7,912</td>
<td>6,823</td>
<td>6,154</td>
<td>5,484</td>
</tr>
</tbody>
</table>

#### Present Value of Portfolios including Scenarios of RPS Sales Revenue

<table>
<thead>
<tr>
<th>Gas</th>
<th>GHG</th>
<th>Likelihood</th>
<th>None</th>
<th>Low</th>
<th>Mid</th>
<th>High</th>
</tr>
</thead>
<tbody>
<tr>
<td>Low</td>
<td>Low</td>
<td>0.5%</td>
<td>11,621</td>
<td>11,306</td>
<td>11,124</td>
<td>10,943</td>
</tr>
<tr>
<td>Mid</td>
<td>Mid</td>
<td>24.8%</td>
<td>11,528</td>
<td>11,210</td>
<td>11,026</td>
<td>10,842</td>
</tr>
<tr>
<td>High</td>
<td>High</td>
<td>10.7%</td>
<td>11,766</td>
<td>11,439</td>
<td>11,250</td>
<td>11,062</td>
</tr>
<tr>
<td>Low</td>
<td>Low</td>
<td>0.5%</td>
<td>12,513</td>
<td>12,142</td>
<td>11,929</td>
<td>11,715</td>
</tr>
<tr>
<td>Mid</td>
<td>Mid</td>
<td>6.6%</td>
<td>16,023</td>
<td>15,666</td>
<td>15,462</td>
<td>15,258</td>
</tr>
<tr>
<td>High</td>
<td>High</td>
<td>3.3%</td>
<td>17,833</td>
<td>17,378</td>
<td>17,115</td>
<td>16,851</td>
</tr>
</tbody>
</table>

**Weighted Present Value**

<table>
<thead>
<tr>
<th></th>
<th>12,104</th>
<th>11,683</th>
<th>11,436</th>
<th>11,190</th>
</tr>
</thead>
</table>

BC Hydro 2008 Long Term Acquisition Plan
The results shown above in Table 5-29 to Table 5-31 illustrate that additional value may be available from the Clean Call Block as compared to the Open Call Block once the resources are on line from future sales of RECs or electricity bundled with RECs into external markets. Higher gas/GHG Cost portfolios result in greater amounts of clean or renewable energy surplus. The relative difference in PV between the portfolios starting with the Clean Call Block and the Open Call Block increases as the assumed price of RECs increases from no incremental price to the high scenario incremental price.

The results show that the Clean Call Block outperforms the Open Call Block at high thermal costs and, when weighted based on portfolio probabilities, on an overall basis.

5.6.5 90 Per Cent Clean Target Analysis

Each of the portfolio analyses for the Base 11 portfolios, the Clean Call Block portfolios and the Open Call Block portfolios was tested with respect to whether it met the 90 per cent clean or renewable target.
The results, presented in Table 5-32, show that many portfolios stayed at or above the 90 per cent target through the planning horizon without having to establish any restrictions on unit commitment decisions. However, there are cases (shaded in Table 5-32) that do drop below the 90 per cent level. Dropping below 90 per cent occurred in the lower thermal cost cases and in large gap cases. The large gap mid thermal and the large gap low thermal portfolio dropped to 89 per cent in 2017 and 2018, respectively. None of the remaining portfolios in Table 5-32 dropped below the 90 per cent until or beyond 2022.

5.6.6 Exchange Rate, Cost of Capital, and Discount Rate

In section 5.9.1 an analysis is provided on the impact of varying Canada/U.S. exchange rates on the portfolio selections and the PV costs of the portfolios for the mid gap scenarios. In section 5.9.2 a similar analysis is provided on the impact of higher cost of capital and discount rates on the portfolio selections and the PV costs of the portfolios. In each case, there was no shift in the selection of resources between gas fired resources and clean resources in the period through 2016.

5.6.7 Regulatory Environment

GHG offset policy, including carbon taxation, continues to be very much on the forefront in North America in general and in B.C. and the western regions in particular. B.C. has recently implemented both a carbon tax and a GHG offset framework. Most, if not all, jurisdictions...
with which BC Hydro is interconnected (western U.S. and Canada), are considering their own requirements. This was described in Chapter 4.

In B.C., the GHG Cap and Trade Act includes the possibility that electricity imports may require GHG offsets. While it is not known when any underlying regulations would be implemented, it is a clear signal that natural gas-fired generation being used to backstop non-firm imports would include significant risk particularly if the imports were at all material.

The market in the U.S. for RECs is increasing rapidly with many jurisdictions having RPSs. These were described in Chapter 4. Much of the market for RECs would be open for BC Hydro to sell into. The sales could be for bundled electricity (clean electricity with its attached REC) physically delivered to a customer in the U.S., or as an unbundled REC that could be re-bundled at a customer’s service territory without physical delivery of electricity from BC Hydro to that customer.

5.6.8 Conclusions

The increasingly stringent, but yet to be completely defined, regulatory environment leads BC Hydro to believe that it is better to place additional weight on clean or renewable resources than on natural gas-fired resources at the present time and in the foreseeable future.

New supply from acquisition processes will be required by 2016 under the mid and high Gaps. The gap in the case of the mid gap is 3,000 to 3,500 GWh/year, if the DSM Option A is developed as planned and the attrition of existing IPP projects does not increase. BC Hydro would need to initiate any acquisition processes to meet any load/resource gaps to 2016 in the 2008/09 timeframe if the process is to be reasonably competitive. Waiting until the next LTAP to consider and then implement an acquisition process would likely mean that any new resources could not be on line by 2016 unless the acquisition process was quite restrictive, and it may mean that the process would need to be focussed on gas-fired resources because of the shorter lead times.

The perfect foresight optimized simulations of the five mid gap cases resulted in 3,700 to 4,600 GWh/year of new IPP resources being selected by 2016. In the high gap cases this increased to 8,500 GWh/year to meet the identified gap of 6,700 GWh/year identified in Table 5-21. The analysis, based on optimized resource selection, including perfect foresight,
indicated that clean resources were selected in all scenarios, while natural gas-fired resources were generally limited to the low to mid gas price scenarios.

The call commitment analysis, based on comparing two specified blocks of new resources, as could be expected to result from a Clean Call Block or an Open Call Block, indicated that the Clean Call Block was relatively resilient to changing conditions. The PV of costs of the simulations across the 11 portfolios showed the Clean Call Block to be slightly lower than the Open Call Block. It also showed that there would be an expectation of increased sales of RPS credits through time.

It is BC Hydro’s conclusion that:

• Given the gap uncertainties, an acquisition of additional resources is warranted; and
• Given the uncertainties surrounding GHG regulation and natural gas costs, BC Hydro should avoid these risks, and target cost-effective clean or renewable resources.
5.7 Peaking Capacity at Mica and Revelstoke

A key issue for the 2008 LTAP: Do one or more of the remaining peaking units at Mica and Revelstoke need to be advanced to retain them as capacity options for BC Hydro’s base plans or contingency plans?

There are three remaining bays at Mica and Revelstoke that could accommodate additional capacity. These would be for Mica Unit 5, Mica Unit 6 and Revelstoke Unit 6.

In this LTAP, the uncertainty with respect to the size of the capacity gap has been described. The need for new capacity resources in the future is uncertain because of the range in possible supply demand gaps and the amount of capacity that is associated with energy that may be acquired from other sources, in this case DSM or acquisition processes. For these sources of uncertainty, the risk, as it relates to peaking capacity, is that BC Hydro may end up short of capacity either at the system level or in a specific load region.

5.7.1 Resource Plan Analysis

The three Mica and Revelstoke units were available capacity options in the portfolio analysis. In the modelling of the base 11 portfolios, the additional peaking capacity was not selected in the low or mid gap cases. In the high gap and high thermal cost scenario, two Mica units were selected in 2016 and 2022, respectively.

In the 11 Site C portfolios, the one Mica unit was again selected for the high gap and high thermal cost scenario in 2016.
Similarly, in the analysis provided in section 5.6, Mica Unit 5 was selected in 2016 and 2020 for the Open Call Block and Clean Call Block cases, respectively, of the call commitment analysis.

5.7.2 Contingency Analysis

Mica Units 5 and 6 are part of the CRPs. Contingency resources are resources that are advanced sufficiently in their development such that the resources can be available in a relatively short timeframe, if necessary. Depending on events that may occur, these capacity options are required to be available. The analysis presented in section 6.4 shows the need to have two of the units advanced as contingency resources.

5.7.3 Conclusion

There is a need to advance two of the capacity resources at Mica and Revelstoke through the Definition phase of development so that the two units will remain available to meet possible high load growth or to be available as contingency resources.
5.8 Site C

The issue for the 2008 LTAP: Is Site C a sufficiently attractive option in the longer term to be maintained as an option by advancing it through its Stage 2 Review?

Site C is included in the ROU as a potential future option. The 2007 Energy Plan mandated BC Hydro to enter into consultation with First Nations, the Province of Alberta and communities regarding the potential project. The funding request for Site C in the 2008 LTAP is to continue through the Stage 2 process.

The decision on whether or not to proceed with Site C to future stages of development will be made by the B.C. Government. As the B.C. Government has not concluded whether Site C will be approved as a resource that BC Hydro can build, Site C will not be relied on as a Base Plan resource in the 2008 LTAP.

To assess Site C’s attractiveness as a resource option, Site C was provided as an option that could be selected in the base set of 9 scenarios. The selection of Site C as an option was based on an economic analysis in the portfolio evaluations.

Site C was offered as an option at the following risk reserves: $0, $150M, $450M, and $1,050M, with the total cost corresponding to those in the Site C Stage 1 Completion Report published in December 2007. The risk reserve in the Site C cost estimate reflects an additional cost over the base project cost and contingency. No other resource options in the 2008 LTAP include a corresponding risk reserve.

These results of the Site C portfolio analysis are compared against the base set of scenarios. Table 5-34 presents the results based on the $150M risk reserve.
## Table 5-34 Portfolio Comparison between Site C not an option and Site C as an Option
($150M Risk Reserve cases)

<table>
<thead>
<tr>
<th>Gap</th>
<th>Cost of Thermal Likelihood PV of portfolios</th>
<th>Resource Selection 2012-2027</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>Gas GHG</td>
<td>Dependable Capacity</td>
</tr>
<tr>
<td></td>
<td>Thermal Clean MCA/REV Site C Thermal Clean MCA/REV Site C</td>
<td></td>
</tr>
<tr>
<td>Low</td>
<td>Low 0.1% 7,809 236 100 - N/A</td>
<td>1,448 801 - N/A</td>
</tr>
<tr>
<td>Small</td>
<td>Mid 6.6% 7,124 - 202 - N/A</td>
<td>2,106 - N/A</td>
</tr>
<tr>
<td></td>
<td>High 3.3% 6,583 - 237 - N/A</td>
<td>2,387 - N/A</td>
</tr>
<tr>
<td>Mid</td>
<td>Low 0.8% 11,577 1,430 189 - N/A</td>
<td>8,775 1,749 - N/A</td>
</tr>
<tr>
<td></td>
<td>Mid 5.2% 11,529 951 369 - N/A</td>
<td>5,836 4,935 - N/A</td>
</tr>
<tr>
<td></td>
<td>High 26.4% 11,859 - 742 - N/A</td>
<td>- 11,303 - N/A</td>
</tr>
<tr>
<td>Large</td>
<td>Low 0.1% 17,692 1,675 680 - N/A 9,384 8,446 - N/A</td>
<td></td>
</tr>
<tr>
<td></td>
<td>Mid 6.6% 17,669 1,528 725 - N/A 5,836 4,935 - N/A</td>
<td></td>
</tr>
<tr>
<td></td>
<td>High 3.3% 18,490 715 953 925 - N/A 4,387 14,937 180 - N/A</td>
<td></td>
</tr>
</tbody>
</table>

Based on the results from Table 5-34, the probable date by which Site C is selected in the analysis is demonstrated in Figure 5-15.
Figure 5-15  Economic Selection Date for Site C in Portfolio Analysis

1. Showing all portfolios, the year that Site C was forecast to enter service, as well as the PV of the portfolio is shown in Table 5-35.

<table>
<thead>
<tr>
<th>Gap</th>
<th>Thermal</th>
<th>No Risk Reserve</th>
<th>$150M Risk Reserve</th>
<th>$450M Risk Reserve</th>
<th>$1,050M Risk Reserve</th>
</tr>
</thead>
<tbody>
<tr>
<td>Low</td>
<td>-</td>
<td>-</td>
<td>-</td>
<td>-</td>
<td>-</td>
</tr>
<tr>
<td>Mid</td>
<td>-</td>
<td>-</td>
<td>-</td>
<td>-</td>
<td>-</td>
</tr>
<tr>
<td>High</td>
<td>2019</td>
<td>6,475</td>
<td>2019</td>
<td>6,555</td>
<td>2026</td>
</tr>
<tr>
<td>Low</td>
<td>2022</td>
<td>11,501</td>
<td>2024</td>
<td>11,533</td>
<td>2024</td>
</tr>
<tr>
<td>Mid</td>
<td>2022</td>
<td>11,340</td>
<td>2022</td>
<td>11,387</td>
<td>2023</td>
</tr>
<tr>
<td>High</td>
<td>2019</td>
<td>11,417</td>
<td>2019</td>
<td>11,500</td>
<td>2021</td>
</tr>
<tr>
<td>Low</td>
<td>2021</td>
<td>17,487</td>
<td>2021</td>
<td>17,562</td>
<td>2023</td>
</tr>
<tr>
<td>Mid</td>
<td>2021</td>
<td>17,313</td>
<td>2021</td>
<td>17,363</td>
<td>2021</td>
</tr>
<tr>
<td>High</td>
<td>2019</td>
<td>17,781</td>
<td>2020</td>
<td>17,841</td>
<td>2020</td>
</tr>
</tbody>
</table>

This analysis shows that Site C is selected in many of the portfolios. It is only in the low gap, low thermal and high risk reserve cases that Site C is not selected as a resource when given as an option.
From this, BC Hydro concludes the following:

- That Site C continues to be an economically attractive future resource in terms of both cost and in terms of providing a back-up should not all of the actions that BC Hydro has included in its Base Plan materialize; and

- That it is reasonable to continue the work required in Stage 2 of the development process to retain Site C as a potential future resource option.
5.9 Additional Modelling Considerations

The following sections address additional modelling considerations that were undertaken to examine their impact on the overall results shown in the portfolio modelling.

5.9.1 Exchange Rate

Forecasts of natural gas prices, market prices for electricity at Mid-C and transmission wheeling rates used for electricity imports and exports are denominated in U.S. dollars. The base case exchange rate forecast between the Canadian and U.S. dollar used to convert these costs for the portfolio analysis in the LTAP 2008 was based on the long term forecast published by the MoF.87

The impact of exchange rate variability was tested with two sensitivities:88

- A stronger Canadian dollar with a value that is ten per cent above the current forecast;
- and
- A weaker Canadian dollar with a value that is ten per cent below the current forecast.

The sensitivity analysis was completed on the five mid-gap scenarios of the 11 base scenarios. The supply side resources that were selected for the portfolios in these five scenarios are shown in Table 5-36.

<table>
<thead>
<tr>
<th>Table 5-36</th>
<th>Resource Selection for the Base Mid Gap Scenarios</th>
</tr>
</thead>
<tbody>
<tr>
<td>Base 5 Scenarios</td>
<td>Cost of Thermal</td>
</tr>
<tr>
<td></td>
<td>Gas</td>
</tr>
<tr>
<td>Low</td>
<td>Low</td>
</tr>
<tr>
<td>Mid</td>
<td>Mid</td>
</tr>
<tr>
<td>Mid High</td>
<td>13.4%</td>
</tr>
<tr>
<td>High Mid</td>
<td>38.8%</td>
</tr>
<tr>
<td>High High</td>
<td>16.3%</td>
</tr>
</tbody>
</table>

The scenarios with stronger and weaker Canadian dollars were simulated in the SO model. All input assumptions were held constant except for the prices of the natural gas, electricity

87 See section 3.5.5 for the exchange rate forecast.

88 The impact of the exchange rate variability on the B.C. or Canadian economy, BC Hydro’s load forecast, or existing or new BC Hydro generation and transmission resources was not considered.
and transmission wheeling rates for imports and exports. Table 5-37 and Table 5-38 present the supply side resources selected in each case.

### Table 5-37  Stronger Canadian Dollar Exchange Rate plus 10 per cent

<table>
<thead>
<tr>
<th>Gap</th>
<th>Cost of Thermal</th>
<th>Dependable Capacity</th>
<th>Firm Energy</th>
<th>Dependable Capacity</th>
<th>Firm Energy</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>Gas</td>
<td>GHG</td>
<td>Likelihood</td>
<td>Thermal</td>
<td>Clean</td>
</tr>
<tr>
<td>Low</td>
<td>Low</td>
<td>0.6%</td>
<td>479</td>
<td>137</td>
<td>2,939</td>
</tr>
<tr>
<td>Mid</td>
<td>Mid</td>
<td>31.0%</td>
<td>479</td>
<td>137</td>
<td>2,939</td>
</tr>
<tr>
<td>Mid</td>
<td>High</td>
<td>13.4%</td>
<td>479</td>
<td>188</td>
<td>2,939</td>
</tr>
<tr>
<td>High</td>
<td>Mid</td>
<td>38.8%</td>
<td>-</td>
<td>272</td>
<td>-</td>
</tr>
<tr>
<td>High</td>
<td>High</td>
<td>16.3%</td>
<td>-</td>
<td>300</td>
<td>-</td>
</tr>
</tbody>
</table>

### Table 5-38  Weaker Canadian Dollar Exchange Rate minus 10 per cent

<table>
<thead>
<tr>
<th>Gap</th>
<th>Cost of Thermal</th>
<th>Dependable Capacity</th>
<th>Firm Energy</th>
<th>Dependable Capacity</th>
<th>Firm Energy</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>Gas</td>
<td>GHG</td>
<td>Likelihood</td>
<td>Thermal</td>
<td>Clean</td>
</tr>
<tr>
<td>Low</td>
<td>Low</td>
<td>0.6%</td>
<td>479</td>
<td>137</td>
<td>2,939</td>
</tr>
<tr>
<td>Mid</td>
<td>Mid</td>
<td>31.0%</td>
<td>479</td>
<td>188</td>
<td>2,939</td>
</tr>
<tr>
<td>Mid</td>
<td>High</td>
<td>13.4%</td>
<td>479</td>
<td>188</td>
<td>2,939</td>
</tr>
<tr>
<td>High</td>
<td>Mid</td>
<td>38.8%</td>
<td>-</td>
<td>300</td>
<td>-</td>
</tr>
<tr>
<td>High</td>
<td>High</td>
<td>16.3%</td>
<td>-</td>
<td>300</td>
<td>-</td>
</tr>
</tbody>
</table>

The results indicate that there is no swing in the selection of thermal resources through 2016 and no material swings in the types of resources being selected overall. For example, natural gas-fired generation (thermal) was not selected in any of the high gas cost scenarios (high or mid GHG offset costs). There are some small shifts in the amount of thermal and clean resources selected in the low and mid natural gas cost scenarios as the exchange rate changes, however, they are immaterial.

The overall PV of the portfolios for each of the five scenarios is presented in Table 5-39.
### Table 5-39: Present Values of the Portfolios for each Scenario as the Exchange Rate is Varied

<table>
<thead>
<tr>
<th>Gap</th>
<th>Gas</th>
<th>GHG Likelihood</th>
<th>-10%</th>
<th>Base</th>
<th>+10%</th>
</tr>
</thead>
<tbody>
<tr>
<td>Low</td>
<td>Low</td>
<td>0.6%</td>
<td>11,769</td>
<td>11,577</td>
<td>11,361</td>
</tr>
<tr>
<td>Mid</td>
<td>Mid</td>
<td>31.0%</td>
<td>11,669</td>
<td>11,528</td>
<td>11,379</td>
</tr>
<tr>
<td>Mid</td>
<td>High</td>
<td>13.4%</td>
<td>11,880</td>
<td>11,758</td>
<td>11,615</td>
</tr>
<tr>
<td>High</td>
<td>Mid</td>
<td>38.8%</td>
<td>11,725</td>
<td>11,777</td>
<td>11,820</td>
</tr>
<tr>
<td>High</td>
<td>High</td>
<td>16.3%</td>
<td>11,807</td>
<td>11,859</td>
<td>11,901</td>
</tr>
</tbody>
</table>

**Weighted Present Value**

|       |       |       | 11,742 | 11,710 | 11,666 |

---

1. Table 5-39 shows that portfolios with higher gas content have lower PV costs under a higher Canadian dollar. The PV costs of the low-low, mid-mid and mid-high Cost of Thermal scenarios decrease as the Canadian dollar strengthens. Conversely, the PV costs of the high-mid and high-high Cost of Thermal portfolios with no gas-fired generation increase with a higher Canadian dollar. However, all of these portfolios have a small PV cost differential.

2. BC Hydro concludes from this analysis that there is no need to consider exchange rate variability on other portfolios.
5.9.2 Cost of Capital and Discount Rate

The base case assumption utilized in the portfolio analysis for both cost of capital and discount rate is six per cent real\(^\text{89}\). Two portfolio sensitivities were analyzed with respect to these parameters: 1) cost of capital increase to eight per cent real; and 2) cost of capital and discount rate increase to eight per cent real.

With respect to the first sensitivity, cost of capital is intended to reflect the costs of capital invested in the resources being selected in each of the portfolios being analyzed. To reflect the impact of a higher cost of capital, a sensitivity of eight per cent real was selected. The sensitivity analysis was completed on the five mid-gap scenarios of the 11 base scenarios. The supply side resources that were selected for the portfolios in these 5 scenarios under the base case assumption are presented in Table 5-40.

Table 5-40 Resource Selection for the Base Mid Gap Scenarios

<table>
<thead>
<tr>
<th>Gap</th>
<th>Cost of Thermal</th>
<th>Dependable Capacity</th>
<th>Firm Energy</th>
<th>Dependable Capacity</th>
<th>Firm Energy</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>Gas</td>
<td>GHG</td>
<td>Likelihood</td>
<td>Thermal</td>
<td>Clean</td>
</tr>
<tr>
<td></td>
<td>MW</td>
<td>MW</td>
<td>MW</td>
<td>GWh</td>
<td>GWh</td>
</tr>
<tr>
<td>Low</td>
<td>Low</td>
<td>0.6%</td>
<td>479</td>
<td>137</td>
<td>2.939</td>
</tr>
<tr>
<td>Mid</td>
<td>Mid</td>
<td>31.0%</td>
<td>479</td>
<td>188</td>
<td>2.939</td>
</tr>
<tr>
<td>Mid</td>
<td>High</td>
<td>13.4%</td>
<td>479</td>
<td>188</td>
<td>2.939</td>
</tr>
<tr>
<td>High</td>
<td>Mid</td>
<td>38.8%</td>
<td>-</td>
<td>319</td>
<td>-</td>
</tr>
<tr>
<td>High</td>
<td>High</td>
<td>16.3%</td>
<td>-</td>
<td>277</td>
<td>-</td>
</tr>
</tbody>
</table>

Table 5-41 presents the supply side resources that were selected for each of the portfolios at the higher cost of capital.

Table 5-41 Resource Selection with an 8 per cent Cost of Capital

<table>
<thead>
<tr>
<th>Gap</th>
<th>Cost of Thermal</th>
<th>Dependable Capacity</th>
<th>Firm Energy</th>
<th>Dependable Capacity</th>
<th>Firm Energy</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>Gas</td>
<td>GHG</td>
<td>Likelihood</td>
<td>Thermal</td>
<td>Clean</td>
</tr>
<tr>
<td></td>
<td>MW</td>
<td>MW</td>
<td>MW</td>
<td>GWh</td>
<td>GWh</td>
</tr>
<tr>
<td>Low</td>
<td>Low</td>
<td>0.6%</td>
<td>479</td>
<td>137</td>
<td>2.939</td>
</tr>
<tr>
<td>Mid</td>
<td>Mid</td>
<td>31.0%</td>
<td>479</td>
<td>188</td>
<td>2.939</td>
</tr>
<tr>
<td>Mid</td>
<td>High</td>
<td>13.4%</td>
<td>479</td>
<td>188</td>
<td>2.939</td>
</tr>
<tr>
<td>High</td>
<td>Mid</td>
<td>38.8%</td>
<td>-</td>
<td>310</td>
<td>-</td>
</tr>
<tr>
<td>High</td>
<td>High</td>
<td>16.3%</td>
<td>-</td>
<td>311</td>
<td>-</td>
</tr>
</tbody>
</table>

\(^{89}\) See Section 3.5.1 for a further description.
As compared to the base assumptions, there is no shift in natural gas resource selections for either the Low-Low or High-High Cost of Thermal portfolios. Similarly, none of the mid-mid, mid-high or high-mid Cost of Thermal portfolios have any shift through 2016. However, by 2027, there is a small shift toward gas-fired generation in these later scenarios.

For the second sensitivity, both the discount rate and the cost of capital were tested at 8 per cent real. The resources selected in the 5 scenarios are presented in Table 5-42.

<table>
<thead>
<tr>
<th>Gap</th>
<th>Cost of Thermal</th>
<th>Cost of Capital 8%; Discount Rate 8%</th>
<th>2012-2016</th>
<th>2012-2027</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>Gas GHG Likelihood</td>
<td>Thermal Dependable Capacity</td>
<td>Firm Energy Thermal Clean</td>
<td>Thermal Dependable Capacity</td>
</tr>
<tr>
<td>Low Low</td>
<td>0.6%</td>
<td>479 137 Thermal 2,939 Clean 1,226</td>
<td>1,430 189 Thermal 8,775 Clean 1,749</td>
<td></td>
</tr>
<tr>
<td>Mid Mid</td>
<td>31.0%</td>
<td>479 188 Thermal 2,939 Clean 1,637</td>
<td>1,194 268 Thermal 7,327 Clean 3,440</td>
<td></td>
</tr>
<tr>
<td>Mid High</td>
<td>13.4%</td>
<td>479 188 Thermal 2,939 Clean 1,637</td>
<td>951 364 Thermal 5,836 Clean 4,869</td>
<td></td>
</tr>
<tr>
<td>Mid High</td>
<td>38.8%</td>
<td>- 319 Thermal - Clean 3,940</td>
<td>236 627 Thermal 1,448 Clean 9,628</td>
<td></td>
</tr>
<tr>
<td>High High</td>
<td>16.3%</td>
<td>- 310 Thermal - Clean 3,716</td>
<td>- 742 Thermal - Clean 11,303</td>
<td></td>
</tr>
</tbody>
</table>

The results from using an eight per cent real cost of capital and discount rate, were virtually identical to those from using an eight per cent real cost of capital and six per cent real discount rate case. Again, there is no material difference in the resources selected relative to the six per cent cost of capital and six per cent discount case.

Table 5-43 presents the PV cost for each of the two sensitivities analyzed above.

<table>
<thead>
<tr>
<th>Gap</th>
<th>Cost of Thermal</th>
<th>Cost of Capital 8%</th>
<th>Cost of Capital 6%</th>
<th>Cost of Capital 8%</th>
<th>Cost of Capital 6%</th>
</tr>
</thead>
<tbody>
<tr>
<td>Gas GHG Likelihood</td>
<td>Base</td>
<td>Weighted Present Value</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Low Low</td>
<td>0.6%</td>
<td>11,577</td>
<td>11,826</td>
<td>10,121</td>
<td></td>
</tr>
<tr>
<td>Mid Mid</td>
<td>31.0%</td>
<td>11,528</td>
<td>11,855</td>
<td>10,140</td>
<td></td>
</tr>
<tr>
<td>Mid High</td>
<td>13.4%</td>
<td>11,758</td>
<td>12,100</td>
<td>10,324</td>
<td></td>
</tr>
<tr>
<td>High Mid</td>
<td>38.8%</td>
<td>11,777</td>
<td>12,504</td>
<td>10,675</td>
<td></td>
</tr>
<tr>
<td>High High</td>
<td>16.3%</td>
<td>11,859</td>
<td>12,584</td>
<td>10,742</td>
<td></td>
</tr>
</tbody>
</table>

Weighted Present Value 11,710 12,257 10,470
The results show that the higher cost of capital had a greater impact on the PV costs as the cost of thermal increases. This is generally because the cost of capital impacts the cost of clean resources (relatively higher capital, lower operating costs) more than gas-fired resources (relatively lower capital costs, higher operating costs). Changing the discount rate and cost of capital showed the same relative impact as cost of capital changes, but the overall numbers were reduced due to the higher discount rate used. However, overall the relative content and ranking of portfolios did not materially change.

BC Hydro concludes from this that the higher cost of capital/discount rate sensitivities would not materially impact the results of the other portfolios analyzed in the LTAP.

5.9.3 Transmission Costs in Portfolios

Section 3.4 describes how the incremental transmission costs were incorporated into the analysis of the 2008 LTAP. Costs and capabilities of the base transmission system and the individual incremental transmission upgrade projects provided by BCTC were input assumptions into the portfolio analysis.

Once the portfolio analysis was completed, the selected portfolios were sent to BCTC for a review of the need for transmission resulting from the resource additions in those portfolios. BCTC then identified the required incremental transmission.

For the base nine portfolios, the PV cost differences resulting from the adjustments to reflect the incremental transmission are as identified in Table 5-44. The differences are the sum of the PV of the incremental transmission based on the timing of the individual transmission upgrades and the cost for the respective upgrades as provided by BCTC and documented in section 3.4.
Table 5-44  Transmission Adjustments to the Base 9 Portfolios

<table>
<thead>
<tr>
<th>Gap</th>
<th>Cost of Thermal</th>
<th>Likelihood</th>
<th>PV of portfolios</th>
<th>Difference in Transmission costs (BCTC analysis - SO analysis)</th>
<th>Adjusted NPV</th>
<th>Difference as a percentage of SO portfolio cost</th>
</tr>
</thead>
<tbody>
<tr>
<td>Gas</td>
<td>GHG</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Small</td>
<td>Low Low</td>
<td>0.1%</td>
<td>7,809</td>
<td>0</td>
<td>7,809</td>
<td>0.00%</td>
</tr>
<tr>
<td></td>
<td>Mid Mid</td>
<td>6.6%</td>
<td>7,124</td>
<td>0</td>
<td>7,124</td>
<td>0.00%</td>
</tr>
<tr>
<td></td>
<td>High High</td>
<td>3.3%</td>
<td>6,583</td>
<td>0</td>
<td>6,583</td>
<td>0.00%</td>
</tr>
<tr>
<td>Mid</td>
<td>Low Low</td>
<td>0.8%</td>
<td>11,577</td>
<td>18</td>
<td>11,595</td>
<td>0.15%</td>
</tr>
<tr>
<td></td>
<td>Mid Mid</td>
<td>52.8%</td>
<td>11,529</td>
<td>14</td>
<td>11,543</td>
<td>0.12%</td>
</tr>
<tr>
<td></td>
<td>High High</td>
<td>26.4%</td>
<td>11,859</td>
<td>11</td>
<td>11,870</td>
<td>0.09%</td>
</tr>
<tr>
<td>Large</td>
<td>Low Low</td>
<td>0.1%</td>
<td>17,692</td>
<td>51</td>
<td>17,743</td>
<td>0.29%</td>
</tr>
<tr>
<td></td>
<td>Mid Mid</td>
<td>6.6%</td>
<td>17,669</td>
<td>49</td>
<td>17,718</td>
<td>0.27%</td>
</tr>
<tr>
<td></td>
<td>High High</td>
<td>3.3%</td>
<td>18,490</td>
<td>57</td>
<td>18,547</td>
<td>0.31%</td>
</tr>
</tbody>
</table>

Table 5-44 shows there to be no adjustments to the small gap scenarios and some adjustments to the mid gap and large gap scenarios. On an overall PV cost basis, the Large Gap differences were approximately 0.3 per cent.

Table 5-45  Transmission Adjustments Portfolios with Site C as an Option

Base 9 Scenarios with Site C as an option (150 M risk reserve included in cost)

<table>
<thead>
<tr>
<th>Gap</th>
<th>Cost of Thermal</th>
<th>Likelihood</th>
<th>PV of portfolios</th>
<th>Difference in Transmission costs (BCTC analysis - SO analysis)</th>
<th>Adjusted NPV</th>
<th>Difference as a percentage of SO portfolio cost</th>
</tr>
</thead>
<tbody>
<tr>
<td>Gas</td>
<td>GHG</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Small</td>
<td>Low Low</td>
<td>0.1%</td>
<td>N/A</td>
<td>-</td>
<td>N/A</td>
<td>N/A</td>
</tr>
<tr>
<td></td>
<td>Mid Mid</td>
<td>6.6%</td>
<td>N/A</td>
<td>-</td>
<td>N/A</td>
<td>N/A</td>
</tr>
<tr>
<td></td>
<td>High High</td>
<td>3.3%</td>
<td>6,555</td>
<td>42</td>
<td>6,597</td>
<td>0.64%</td>
</tr>
<tr>
<td>Mid</td>
<td>Low Low</td>
<td>0.8%</td>
<td>11,533</td>
<td>27</td>
<td>11,560</td>
<td>0.23%</td>
</tr>
<tr>
<td></td>
<td>Mid Mid</td>
<td>52.8%</td>
<td>11,387</td>
<td>27</td>
<td>11,414</td>
<td>0.24%</td>
</tr>
<tr>
<td></td>
<td>High High</td>
<td>26.4%</td>
<td>11,500</td>
<td>63</td>
<td>11,563</td>
<td>0.55%</td>
</tr>
<tr>
<td>Large</td>
<td>Low Low</td>
<td>0.1%</td>
<td>17,562</td>
<td>58</td>
<td>17,620</td>
<td>0.33%</td>
</tr>
<tr>
<td></td>
<td>Mid Mid</td>
<td>6.6%</td>
<td>17,363</td>
<td>58</td>
<td>17,421</td>
<td>0.34%</td>
</tr>
<tr>
<td></td>
<td>High High</td>
<td>3.3%</td>
<td>17,841</td>
<td>2</td>
<td>17,843</td>
<td>0.01%</td>
</tr>
</tbody>
</table>

Table 5-45 presents the transmission adjustments to scenarios where Site C with a $150 million risk reserve. In this case, Site C was not selected for the small gap, low and mid thermal cases. For other scenarios there were differences in the same order of magnitude as those seen with the base 9 scenarios.
5.9.4 Long Portfolio Impacts / Exposure to External Markets

BC Hydro can be “long” in energy supply from either a planning or operating perspective. From the planning perspective, being “long” would be a consequence of having more firm energy supply than required to meet its firm requirements (a positive energy gap). From an operating perspective, there is potentially additional energy supply from having non-firm energy such as Heritage non-firm hydro.

The impact of being “long” results in an exposure to export markets. The impact of this exposure depends on:

- the ability to mitigate any possible loss in value by storing and shaping the energy for delivery into high value markets;
- the price that can be received by selling the additional capacity or energy;
- the availability of transmission capacity; and
- any possible value-adding attributes that BC Hydro can offer.

Long Position in Firm Energy

The physical measurement of being “long” in firm energy is identified as a positive gap in the load/resource balance, and is modelled in the portfolio analysis. In the 2008 LTAP, the SO model establishes portfolios of resources that meet the firm capacity and energy requirements over the planning horizon. Once resources are selected, the model analysis is based on the average energy capability of the supply resources and therefore specifically calculates the costs of generating electricity that is sold into the market; the cost including losses of delivery to Mid-C from the relevant generator in the BC Hydro system; and the transmission limits and the most economic time period in a year to sell the energy, based on average hydro conditions and operating within the identified constraints. In the SO analysis, the average conditions were based on 4,200 GWh/year of non-firm Heritage hydro energy.

The portfolio analysis specifically considered portfolios and scenarios combinations with varying levels of surplus capacity and energy. The surplus net energy is forecast to be sold into the market at the most appropriate time period for the then current market price net of wheeling and losses.
Table 5-46 identifies the ranges in differential net export positions that resulted from the portfolios resulting from the Base 11 scenarios.

<table>
<thead>
<tr>
<th>Base 11 Scenarios</th>
<th>Gap</th>
<th>Cost of Thermal</th>
<th>Likelihood</th>
<th>Annual Net Export 2016 - 2027 (GWh/year)</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td></td>
<td>Gas</td>
<td>GHG</td>
<td>Highest</td>
</tr>
<tr>
<td>Small</td>
<td>Low</td>
<td>Low</td>
<td>0.1%</td>
<td>5165</td>
</tr>
<tr>
<td></td>
<td>Mid</td>
<td>Mid</td>
<td>6.6%</td>
<td>5448</td>
</tr>
<tr>
<td></td>
<td>High</td>
<td>High</td>
<td>3.3%</td>
<td>6010</td>
</tr>
<tr>
<td>Mid</td>
<td>Low</td>
<td>Low</td>
<td>0.5%</td>
<td>4350</td>
</tr>
<tr>
<td></td>
<td>Mid</td>
<td>Mid</td>
<td>24.8%</td>
<td>5197</td>
</tr>
<tr>
<td></td>
<td>High</td>
<td>Mid</td>
<td>10.7%</td>
<td>5528</td>
</tr>
<tr>
<td></td>
<td>High</td>
<td>High</td>
<td>31.0%</td>
<td>6478</td>
</tr>
<tr>
<td></td>
<td>High</td>
<td>High</td>
<td>13.0%</td>
<td>6478</td>
</tr>
<tr>
<td></td>
<td>Low</td>
<td>Low</td>
<td>0.1%</td>
<td>5589</td>
</tr>
<tr>
<td></td>
<td>Mid</td>
<td>Mid</td>
<td>6.6%</td>
<td>5843</td>
</tr>
<tr>
<td></td>
<td>High</td>
<td>High</td>
<td>3.3%</td>
<td>6554</td>
</tr>
</tbody>
</table>

As a result of the above, the impact of being long in dependable capacity and firm energy, including the associated average non firm energy, is modelled in all portfolio analysis completed for all scenarios identified in Chapter 5.

Planning Horizon Market Price

Market prices in the LTAP were described in Chapter 4. The scenarios of market prices were developed from plausible future scenarios of electricity and gas market conditions, and include conditions of varying levels of capacity surpluses in the WECC. As a result, the market price scenarios reflect the impact of regional capacity surpluses on the market prices, including periods of depressed prices.

The ranges in surplus capacity in the WECC that were identified in the development of the market price forecasts are presented in Table 5-47.

Table 5-47 Capacity Surplus in WECC in 2020

<table>
<thead>
<tr>
<th>Market Price Forecast</th>
<th>High</th>
<th>Mid</th>
<th>Low</th>
</tr>
</thead>
<tbody>
<tr>
<td>Surplus Capacity (MW)</td>
<td>58,529</td>
<td>59,244</td>
<td>72,550</td>
</tr>
<tr>
<td>Surplus Capacity (per cent)</td>
<td>30.6</td>
<td>31.0</td>
<td>37.9</td>
</tr>
</tbody>
</table>
Market prices, and in particular the forecasts of market heat rate in this LTAP provide a relatively wide range of market conditions into which BC Hydro is testing its LTAP action items.

The market heat rate for each of the forecasts is provided in Figure 5-16.

Figure 5-16  Capacity Surplus in WECC in 2020 Average Annual Market Heat Rate

All portfolio modelling used, as an input, the three market price scenarios. As a result, the impacts of varying capacity surpluses in the WECC and the associated impacts on heat rates and market prices were reflected in the analysis in Chapter 5.

Long Positions from Operational Non-Firm Energy

HYSIM is BC Hydro’s model that simulates the long-term operation of the BC Hydro system, including the effects of the full 60 years of water record. The following describes an approximation of the operational impacts modelled in HYSIM in a simplified but generally accurate representation. In total, the following identifies the general relationship between non-firm Heritage hydro surplus and non-firm net revenue. The description is based on values for the year 2017.

BC Hydro’s non-firm energy from the Heritage hydroelectric resources can vary by over 11,000 GWh/year, and averages approximately 4,200 GWh/year. In addition, BC Hydro
1. expects to purchase approximately 1,600 GWh/year from non-firm IPP purchases from existing or committed EPAs in that year. On a cumulative basis, the profile of the approximate non-firm energy is presented in Figure 5-17.

![Figure 5-17 Profile of Non-firm Heritage Hydro Energy and Non-firm IPP Energy](image)

In this way, the non-firm energy volumes for the full range of water years and including the impacts of non-firm IPP energy are incorporated into the planning analysis.

**Market Price Correlation with Operational (Non-Firm) Energy Surpluses**

4. The primary correlation of market prices with secondary energy volumes is with respect to periods when the Columbia basin, as a whole, has relatively more or less energy. BC Hydro analysis generally shows some correlation between the market prices and the Columbia River flow at the Dalles. Based on past market simulation completed in the 2001/2002 timeframe, BC Hydro derived an approximate correlation between market prices and flow volume at the Dalles. This analysis results in a per-unit correlation factor that is still considered to be a reasonable representation for long-term planning.

5. From the analysis, BC Hydro has calculated the per-unit multipliers for each HLH/LLH period for each of the 60 water years used in planning analysis. BC Hydro incorporates this price correlation in its HYSIM modelling.
Figure 5-18 presents the relationship between market prices and the BC Hydro non-firm energy position, including a trend line of the market price based on prices in 2017 from the portfolio modelling results referenced to 5,000 GWh/year of export.

The result shows the simulated correlation between Mid-C prices and Heritage hydro non-firm energy volume. This is primarily reflective of the correlation between secondary energy surpluses in the U.S. Pacific Northwest and BC Hydro, and not of BC Hydro’s direct impact on the Mid-C prices.

The market price correlation to non-firm Heritage hydro is reflected in the HYSIM analysis. This correlation is a link back to the market price scenarios described above and therefore reflects the impacts of varying levels of capacity surpluses and market heat rates in the WECC.

Transmission Capability to Obtain Market Access

HYSIM models transmission limits (import and export) for the HLH and LLH periods (24 periods per year). The dispatch analysis takes into account the operational parameters, including the 60 years of stream flow record, the ability to store water (energy), the interconnection limits transmission costs and market prices for each period.
An approximation of the impact of energy being shifted from higher to lower value periods as the amount of export increases is provided in Figure 5-19. It is based on the same underlying conditions as described for Figure 5-18.

![Per Unit Impact of Export Limit Impact on BC Border Market Price](image)

**Figure 5-19** Per Unit Impact of Export Limit Impact on BC Border Market Price

Net Revenue Associated with Secondary Energy

The incremental cost of producing secondary energy to BC Hydro is essentially the water rental cost, while the incremental energy cost for the non-firm energy from the F2006 Call is approximately $73/MWh.

Based on the non-firm energy volumes presented in Figure 5-17 and reflecting:

- The impact on Mid C market prices of hydro surpluses in the U.S. Pacific Northwest (Figure 5-18);
- The export transmission limits (Figure 5-19);
- The approximate cost of non-firm energy identified above; and
- The incremental cost of Heritage hydro water,

BC Hydro’s net revenue from non-firm energy that would result is presented in Figure 5-20.
As can be seen, the net revenue continues to increase as the amount of non-firm energy increases. Relative to the 4,200 GWh of Heritage non-firm energy modelled in the SO (vertical line represented at 42 per cent in Figure 5-20), any additional non-firm energy above the modelled point would add value to the simulation.

Figure 5-20  Expected Cost and Revenue from Non-Firm Energy reflecting the Correlation between Mid C Prices and Heritage Hydro Non-Firm Energy

![Diagram showing expected cost and revenue from non-firm energy.]

Market Opportunities to Add Value from Exported Energy

BC Hydro continues to have the ability, through Powerex Corp. (Powerex), to have its electricity marketed into high value markets. In accordance with the BC Hydro and Powerex Transfer Pricing Agreement, BC Hydro surplus electricity sales to Powerex are priced at the Mid-C index adjusted for transmission and losses. Thus BC Hydro effectively earns a market price on all its sales of surplus electricity.

New products such as the sale of RECs from surplus non-firm clean or renewable energy, whether bundled with the additional electricity or sold separately, would be additional products and will likely have a positive effect as the amount of non-firm energy, in any one year, increases.
Conclusion

BC Hydro will have electricity surplus to its domestic needs as it moves forward. This can be
as a result of being “long” in firm supply (positive planning load/resource gap) or from
operational impacts of non-firm energy supply variability.

The result of being “long” is that BC Hydro will be selling energy into external markets and
therefore exposed to market access restrictions, market availability, product type
requirements and market prices for the products.

The effects of being “long” from a planning perspective are addressed through the portfolio
analysis presented in Chapter 5, through:

• Modelling of the firm and average capability of existing and planned resources in B.C.;
• Specific modelling of small, medium and large gaps;
• Market pricing based on scenarios of market prices that include varying levels of surplus
  in the WECC and a wide range of market heat rates; and
• Specific inclusion of interconnection limits to external markets and inter-area transmission
  limits within B.C.

Broader implications of being “long” have been incorporated through more detailed analysis
of the impacts of the variability of the Heritage hydroelectric energy and the potential
correlated variability in non-firm energy being purchased from IPPs. The effects are included
through:

• Specific modelling of the 60-year hydroelectric record;
• Inclusion of the estimated effect of the correlation between non-firm IPP energy acquired
  in the F2006 Call; and
• Recognition of the correlation of the Mid-C market price to BC Hydro non-firm hydro
  energy volumes.

The analysis shows that the variability of net revenues from non-firm energy can be negative
in years with relatively low amounts of Heritage hydro due to the cost of non-firm purchases
from IPPs, but becomes increasingly positive as the Heritage hydro non-firm volumes
increase.
### Table 5-48: Summary of Portfolio Results

**Risk Framework Uncertainties**

<table>
<thead>
<tr>
<th>Portfolio Modelling Inputs</th>
<th>2012 - 2016</th>
<th>2012 - 2027</th>
<th>Scenario Specific Comments</th>
</tr>
</thead>
<tbody>
<tr>
<td><strong>Dependable Capacity</strong></td>
<td>Clean</td>
<td>Thermal</td>
<td>Clean</td>
</tr>
<tr>
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<td>0</td>
<td>0</td>
</tr>
<tr>
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<td>0</td>
<td>0</td>
</tr>
<tr>
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<td>137</td>
<td>0</td>
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<tr>
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<td>0</td>
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<tr>
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<td>188</td>
<td>2939</td>
</tr>
<tr>
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<td>2939</td>
</tr>
<tr>
<td>Mid Mid High 31.0% Option A 2015 unavailable 3000</td>
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<td>0</td>
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<td>3094</td>
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<tr>
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</table>

**Portfolio Modelling Outputs**

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<th>Gap</th>
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<th>LMM</th>
<th>ISD</th>
<th>Site C</th>
<th>BGS</th>
<th>GWh</th>
<th>Thermal</th>
<th>Clean</th>
<th>Thermal</th>
<th>Clean</th>
<th>PV</th>
</tr>
</thead>
<tbody>
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<td>3000</td>
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<td>0</td>
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<td>236</td>
<td>100</td>
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<td>-</td>
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<td>3000</td>
<td>0</td>
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<td>0</td>
<td>1226</td>
<td>0</td>
<td>1,448</td>
<td>801</td>
<td></td>
</tr>
<tr>
<td>Mid Mid Mid 24.8%</td>
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<td>1637</td>
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<td>2939</td>
<td>1637</td>
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<td>8456</td>
<td>715</td>
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<td>4,387</td>
<td>14,937</td>
</tr>
</tbody>
</table>

The size of the gap is the major driver of costs. Because gas prices are linked to export markets, there is no simple relationship between gas prices and PV of each portfolio. GHG costs have a relatively minor impact. The volume of thermal projects picked up decreases at higher gas prices, but some thermal is still needed in higher gap cases.
**Risk Framework and Portfolio Analysis**

**Risk Framework Uncertainties**

- Portfolio Modelling Inputs
- Portfolio Modelling Outputs

**Scenario Specific Comments**

**Portfolio Modelling Inputs**

<table>
<thead>
<tr>
<th>Gap</th>
<th>Cost of Gas</th>
<th>Cost of GHG</th>
<th>Relative Likelihood</th>
<th>DSM</th>
<th>LM</th>
<th>ISD</th>
<th>Site C</th>
<th>BGS Firm GWh</th>
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</thead>
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<tr>
<td>2015 - 2016</td>
<td>2012 - 2022</td>
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<td></td>
<td></td>
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**Portfolio Modelling Outputs**

<table>
<thead>
<tr>
<th>Risk Framework Uncertainties</th>
<th>Portfolio Modelling Outputs</th>
<th>Scenario Specific Comments</th>
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<tbody>
<tr>
<td>Relative Likelihood</td>
<td>DSM</td>
<td>LM</td>
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</table>

These scenarios with no DSM were compared to the Base 11 Scenarios, where DSM was Option A.

Small Low Low 0.1% none 2015 unavailable 3000 813 246 4542 2625 1,988 614 9,847 8,540 $12,525

Small Mid Mid 6.6% none 2015 unavailable 3000 715 307 4387 3433 1,626 643 9,083 5,200 $12,794

Small High High 3.3% none 2015 unavailable 3000 0 495 0 7673 715 934 4,387 14,433 $13,691

Mid Low Low 0.5% none 2015 unavailable 3000 1038 478 4800 5087 2,811 940 10,962 14,317 $18,326

Mid Mid Mid 24.8% none 2015 unavailable 3000 1252 426 6342 5464 2,360 967 10,466 14,712 $18,842

Mid Mid High 10.7% none 2015 unavailable 3000 1147 477 6144 5875 2,262 941 10,311 14,330 $19,289

Mid High Mid 31.0% none 2015 unavailable 3000 294 761 464 11170 1,724 1,046 9,238 16,182 $20,611

Mid High High 13.0% none 2015 unavailable 3000 1,822 1,002 9,393 15,830 $20,678

High Low Low 0.1% none 2015 unavailable 3000 1688 478 7791 5087 2,854 1,459 10,930 19,913 $23,204

High Mid Mid 6.6% none 2015 unavailable 3000 1986 502 7945 6419 2,654 1,467 10,930 20,190 $23,636

High Mid High 3.3% none 2015 unavailable 3000 1303 761 5315 11170 2,213 1,477 10,011 20,958 $26,606

The increased gap is filled with a mixture of renewables and thermal projects. The mixture between these two types of resources is determined both by their cost and by the need for firm energy capacity over the planning horizon.

Small Mid Mid 6.6% Option A 2015 unavailable 3000 479 188 2939 1637 479 188 2,939 1,637 $9,353

Small High High 3.3% Option A 2015 unavailable 3000 479 391 2939 5781 753 953 4,448 14,937 $17,833

Mid Low Low 0.5% Option A 2015 unavailable 3000 236 137 1448 1226 951 266 5,836 3,072 $11,187

Mid Mid Mid 24.8% Option A 2015 unavailable 3000 236 137 1448 1338 951 271 5,836 3,103 $10,993

Mid Mid High 10.7% Option A 2015 unavailable 3000 0 237 0 2579 - 625 - 9,358 $10,997

Mid High Mid 31.0% Option A 2015 unavailable 3000 0 218 0 2579 - - - - $11,674

Mid High High 13.0% Option A 2015 unavailable 3000 0 218 0 2579 - - - - $11,674

High Low Low 0.1% Option A 2015 unavailable 3000 958 237 5878 2387 1,909 480 11,714 7,667 $15,683

High Mid Mid 6.6% Option A 2015 unavailable 3000 479 340 2939 4349 1,479 567 9,075 8,220 $16,376

High Mid High 3.3% Option A 2015 unavailable 3000 0 579 0 7823 958 870 5,878 13,645 $17,279

The large amount of energy and associated capacity saved under DSM High Gap cases, the need for new resources is almost removed.

High High High 3.3% Option B 2015 unavailable 3000 0 579 0 7823 958 870 5,878 13,645 $17,279

These portfolios contain a substantial portion of thermal resources since they start out with a GHG scenario.

High Low Low 0.1% Option B 2015 unavailable 3000 1488 478 7791 5987 2,654 1,459 10,930 19,913 $23,204

High Mid Mid 6.6% Option B 2015 unavailable 3000 1586 502 7945 6419 2,654 1,467 10,930 20,190 $23,636

High High High 3.3% Option B 2015 unavailable 3000 479 391 2939 5781 753 953 4,448 14,937 $17,833

These portfolios contain mostly clean resources since they start out with a resource mix that reflect an optimal allocation under a Mid-gap, High gas, Mid-GHG scenario.
## Risk Framework and Portfolio Analysis

### Risk Framework Uncertainties

<table>
<thead>
<tr>
<th>Portfolio Modelling Inputs</th>
<th>Dependent Capacity</th>
<th>Firm Energy</th>
</tr>
</thead>
<tbody>
<tr>
<td>DSM</td>
<td>EM</td>
<td>ISD</td>
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<table>
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<th>Gap</th>
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<th>Likelihood</th>
<th>DSM</th>
<th>EM</th>
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<th>Site C</th>
<th>BGS</th>
<th>Cost of Gas</th>
<th>Cost of GHO</th>
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<th>Site C as an option in (Risk Reserve)</th>
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<td>Low</td>
<td>Low</td>
<td>Option A</td>
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<td>3000</td>
<td>0</td>
<td>0</td>
<td>0</td>
<td>0</td>
<td>0</td>
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<td>Small</td>
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<td>3000</td>
<td>0</td>
<td>0</td>
<td>0</td>
<td>0</td>
<td>-</td>
</tr>
<tr>
<td>Small</td>
<td>High</td>
<td>High</td>
<td>Option A</td>
<td>2015</td>
<td>2019</td>
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<td>Option A</td>
<td>2015</td>
<td>2015</td>
<td>3000</td>
<td>479</td>
<td>137</td>
<td>2939</td>
<td>1338</td>
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<tr>
<td>Mid</td>
<td>Mid</td>
<td>Mid</td>
<td>Option A</td>
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<td>3000</td>
<td>479</td>
<td>188</td>
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<tr>
<td>High</td>
<td>Low</td>
<td>Low</td>
<td>Option A</td>
<td>2015</td>
<td>2019</td>
<td>2019</td>
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<td>272</td>
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<td>High</td>
<td>Mid</td>
<td>Mid</td>
<td>Option A</td>
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<td>2021</td>
<td>2021</td>
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<td>3094</td>
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<tr>
<td>High</td>
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### Portfolio Modelling Outputs

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<td>236</td>
<td>100</td>
</tr>
<tr>
<td>202</td>
<td>-</td>
</tr>
<tr>
<td>1,037</td>
<td>-</td>
</tr>
<tr>
<td>911</td>
<td>1,137</td>
</tr>
<tr>
<td>715</td>
<td>1,170</td>
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<td>1,410</td>
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<td>1,826</td>
<td>1,370</td>
</tr>
<tr>
<td>1,506</td>
<td>1,375</td>
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</table>

### Scenario Specific Comments

- Here Site C is an option for all cases. Site C is not picked up when the Gap is small and thermal costs are in the low to mid range. However, Site C is picked up as an economic option in all other scenarios.
- With no risk reserve, Site C is picked up for one mid scenario.
- Site C is not picked up when the Gap is small and thermal costs are in the low to mid range. This high risk reserve, as well as delaying the economic start date, also means Site C is not picked up for one mid gap scenario.

**Risk Framework and Portfolio Analysis**

**BC Hydro 2008 Long Term Acquisition Plan**

5-95
### Risk Framework and Portfolio Analysis

#### Risk Framework Uncertainties

<table>
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<th>Scenario Specific Comments</th>
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<td>Cost of GHG</td>
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<td><strong>Firm Energy</strong></td>
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<tr>
<td><strong>2012 - 2016</strong></td>
<td></td>
<td></td>
</tr>
<tr>
<td><strong>2012 - 2027</strong></td>
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</table>

#### Exchange Rates +10%:

These scenarios were run with exchange rates were 10% above the assumption used in the modelling above. These were compared against the base 5 scenarios.

- There is no swing in the selection of resources through 2016 with a stronger Canadian dollar (+10%) and no significant shift in the resource balance over the planning period.

#### Exchange Rates -10%:

These scenarios were run with exchange rates were 10% below the assumption used in the modelling above. These were compared against the base 5 scenarios.

- There is no swing in the selection of resources through 2016 with a stronger Canadian dollar (+10%) and no significant shift in the resource balance over the planning period.

#### Discount Rates Sensitivity -8% real:

These scenarios were run with the cost of capital increased to 8%. These were compared against the base 5 scenarios.

- There is no shift in the balance between clean and thermal resources by 2016. By 2027, there is a small shift towards more thermal generation.

#### Cost of Capital and Discount Rate -8% real:

These scenarios were run with the cost of capital raised to 8% and the discount rate raised to 8%. These were compared to the base 5 scenarios.

- These results are virtually identical to the above sensitivity. Again, there is no material difference to the resources selected over the planning period.
2008 Long Term Acquisition Plan

BCHydro

Volume 1

Chapter 6

LONG TERM ACQUISITION PLAN
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<th>CRP#1</th>
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<td>Table 6-19</td>
<td>Energy Contingencies #2</td>
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<td>Table 6-20</td>
<td>CRP#2</td>
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<td>Table 6-21</td>
<td>Base Resource Plan</td>
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<td>Table 6-22</td>
<td>Contingency Resource Plan</td>
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6.1 Introduction

This chapter presents BC Hydro’s 2008 LTAP, which identifies the steps BC Hydro proposes to take during the next two to three years to implement this plan. It is based on guidance provided by BC Hydro’s analysis and results described in Chapters 1 through 5 of this Application as well as feedback from intervenors, First Nations and other stakeholders.

The remainder of this chapter is laid out as follows:

- Section 6.2 details the actions that BC Hydro proposes to carry out to address the load/resource gap described in section 2.4, along with the orders sought from the BCUC, the justification, implementation steps, risk mitigation measures and proposed future approval process with respect to each proposed action;

- Section 6.3 depicts the load/resource balance that will result from a successful implementation of the 2008 LTAP;

- Section 6.4 contains BC Hydro’s two CRPs to address load growth uncertainty and resource acquisition uncertainty (section 6.4.2) and sets out BC Hydro’s contingency plans to address 5L83 transmission supply uncertainty (section 6.4.3).

6.2 Proposed Actions to Meet the Load/Resource Gap

6.2.1 DSM Implementation Plan

6.2.1.1 Order Sought

BC Hydro is requesting a determination pursuant to subsection 44.2(3)(a) of the UCA that expenditures of $418 million required to implement the DSM Plan in F2009, F2010 and F2011 are in the public interest. This represents a portion of the DSM expenditures identified in the DSM Plan attached as Appendix K because some of these expenditures, such as rate structures and information technology, are or will be included in other BCUC proceedings. See Table 6-1.
Table 6-1  DSM Expenditure Request ($ million)

<table>
<thead>
<tr>
<th></th>
<th>F2009</th>
<th>F2010</th>
<th>F2011</th>
<th>3-Year Total</th>
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<td>DSM Plan Costs</td>
<td>129.8</td>
<td>161.8</td>
<td>195.6</td>
<td>487.3</td>
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<td>Less DSM Costs to be</td>
<td>25.1</td>
<td>31.6</td>
<td>36.6</td>
<td>93.4</td>
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<tr>
<td>Included in Other</td>
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<td>Expenditure Requests</td>
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<td></td>
<td></td>
<td></td>
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<tr>
<td>Sub-Total</td>
<td>104.7</td>
<td>130.2</td>
<td>159.0</td>
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<tr>
<td>Add Capital Overhead</td>
<td>7.4</td>
<td>8.0</td>
<td>8.7</td>
<td>24.1</td>
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<td>138.2</td>
<td>167.7</td>
<td>418.0</td>
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<td>Request in 2008 LTAP</td>
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</table>

1 The 2008 LTAP DSM expenditure request of $393.9 (without capital overhead) is broken down as follows: (1) programs - $308.9; (2) Codes and standards - $6.5 million; and (3) Portfolio level activities excluding codes and standards - $78.5 million. Refer to Sub-Appendix C of the DSM Plan (Appendix K) for additional details concerning the expenditure request.

2 The DSM Plan figures presented in this section are similar to but not equal to those for DSM Option A presented in section 3.2. Following the submittal of that Option for the 2008 LTAP portfolio analysis, it was updated for the purpose of this expenditure request to include the Residential Inclining Block (RIB) rate structure as filed in February 2008 with the BCUC as well as other updates and refinements. These changes do not have a material effect on the portfolio analysis results and were made so that the DSM expenditure request would be based on the best available information.\(^70\)

3 BC Hydro also seeks specific endorsement from the BCUC that the amortization period for deferred DSM expenditures should remain at ten years. Finally, BC Hydro requests that the BCUC endorse the residential Low Income DSM program, which has a Non-Participant Test (Ratepayer Impact Measure) benefit-cost ratio of 0.6 and an All Ratepayers Test (Total

\(^70\) As noted in section 3.2, three sets of DSM figures are presented in this 2008 LTAP. Planned energy and capacity savings presented in section 3.2 are the first set and represent the starting point. They were inputs to the probability assessment discussed in Chapter 5 which produced a second set of figures, comprising high, mid and low DSM outcomes with associated probabilities, which were inputs to the portfolio analysis discussed in Chapter 5. A third set for Option A, presented in this section, resulted from updates and refinements that were carried out after it was submitted for the portfolio analysis so that the DSM expenditure request would be based on the best available information. The differences between each set are small and not material for portfolio analysis.
Resource Cost) benefit-cost ratio of 0.9. In BC Hydro’s submission, the residential low
income DSM program is not a tariff. Justification for the residential Low Income DSM
program is found in Sub-Appendix I of the DSM Plan (Appendix K).

BC Hydro is also seeking BCUC endorsement of the following changes to DSM related
Directives.

- The rescission of Directives 62 and 64 of the F05/F06 RRA Decision. Pursuant to
  Directives 62 and 64 BC Hydro is to consider Load Displacement as a “supply side
  alternative” and is to remove all costs and benefits associated with all Load Displacement
  projects from the calculation of the three threshold tests and from DSM statistics for DSM
  reporting purposes. Directives 62 and 64, however, are no longer applicable due to
  Section 1 of the 2008 UCA Amendments. Section 1 provides that “demand side
  measures means a rate, measure, action or program... (b) to reduce the energy demand
  a public utility must serve.” Load Displacement projects involve new self-generation at
  customer sites with a resultant decrease in the purchase of electricity from BC Hydro,
  and thus qualify as a demand-side measure under the above referenced section (b) of
  the UCA definition set out above.

- The amendment of Directive 69 of the F05/F06 RRA Decision and Directive 16 of the
  2006 IEP/LTAP Decision directing that DSM performance reports, as described in
  Directive 16, be filed with the BCUC on an annual basis. With respect to DSM monitoring
  the BCUC previously directed BC Hydro to file semi-annual reports on DSM with the
  BCUC. The proposed DSM Plan attached as Appendix K to the 2008, Exhibit B-1-1 is
  more complex than previous DSM period for filing initiatives, with multiple DSM tools (rate
  structures, codes and standards and programs) that require longer time periods to
  measure impacts and to provide meaningful reporting on the progress of the DSM Plan.
  BC Hydro is requesting that the BCUC amend the DSM reporting directive to move from
  filing semi-annual reports to filing annual reports on the performance of DSM with the
  BCUC. The revised period for filing would allow for additional requested time to collect
  data and perform analysis on the overall performance of the DSM Plan while still closely
  monitoring progress within the LTAP cycles. Filing DSM performance reports on an
  annual basis also aligns with section 43(1)(ii) of the UCA, which provides that public
  utilities are to file “a report submitted annually and in the manner the BCUC requires,
  regarding the demand-side measures taken by the public utility during the period
  addressed by the report, and the effectiveness of those measures”. Please refer to
  BC Hydro’s revised requested final Order, attached as amended Appendix A to the
  2008 LTAP, Exhibit B-1-6.
6.2.1.2 Justification

The DSM Plan is forecast to save 10,610 GWh/year and 1,760 MW in F2020, which is the milestone year for the 2007 Energy Plan’s 50 per cent conservation target. As shown in Table 6-2, for the F2009-F2011 period the DSM plan will achieve 2,345 GWh per year in cumulative energy savings, including 1,038 GWh per year from residential customers, 525 GWh per year from commercial customers and 782 GWh per year from industrial customers. This includes 78 GWh per year of savings that will be enabled by Smart Metering Infrastructure (SMI). The DSM energy savings shown in Table 6-2 are at the customer meter, and do not include the savings attributable to distribution or transmission losses; related capacity savings are set out in Table 6-3.

<table>
<thead>
<tr>
<th>Table 6-2</th>
<th>DSM Plan Cumulative Energy Savings in F2020 (GWh/year)</th>
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<td>Rate Structures</td>
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<tr>
<td>Residential</td>
<td>2,760</td>
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<td>Commercial</td>
<td>500</td>
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<td>Industrial</td>
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<td>Total</td>
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<td>Residential</td>
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<td>Commercial</td>
<td>65</td>
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<tr>
<td>Industrial</td>
<td>14</td>
</tr>
<tr>
<td>Total</td>
<td>662</td>
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71 BC Hydro is required by section 64.04 (3) of the UCA to install smart meters by the end of calendar 2012. The full scope of the smart meters to be installed is dependant, among other things, on regulations which have not yet been passed. Currently, the DSM Plan includes 78 GWhs of savings that are enabled by SMI.
1. Table 6-4 indicates utility costs.

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<th>DSM Plan Utility Costs</th>
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<td>($ million)</td>
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<td>Residential</td>
<td>161</td>
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<tr>
<td>Commercial</td>
<td>129</td>
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<td>Industrial</td>
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</tr>
<tr>
<td>Portfolio Level</td>
<td>92</td>
</tr>
<tr>
<td>Total</td>
<td>487</td>
</tr>
</tbody>
</table>

The DSM Plan will generate electricity savings at a lower cost than new electricity supply.

2. Table 6-5 presents benefit-cost ratios for the three standard DSM cost tests. Ratios are presented for the three DSM strategic elements as a group, for rate structures and programs as a group and for programs alone.

<table>
<thead>
<tr>
<th>Table 6-5</th>
<th>DSM Plan Benefit-Cost Ratios</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>Utility Test</td>
</tr>
<tr>
<td>Residential</td>
<td>9.4</td>
</tr>
<tr>
<td>Commercial</td>
<td>3.5</td>
</tr>
<tr>
<td>Industrial</td>
<td>4.1</td>
</tr>
<tr>
<td>Portfolio Total</td>
<td>5.4</td>
</tr>
</tbody>
</table>

C&S = codes and standards; RS = rate structures; P = DSM programs.

3. For the purpose of DSM Plan decision-making, BC Hydro considers the cost-effectiveness of rate structures and programs as a group, excluding codes and standards. This is a conservative view that recognizes that codes and standards will require different levels of

72 Note the funding for activities that will be pursued through separate approval processes have been removed from the DSM Plan costs for the purpose of expenditure approval. The related costs and energy for these activities are included in the overall DSM Plan costs, energy targets, and cost-effectiveness analysis. Total Plan costs over 20 years amount to $4.5 billion.
BC Hydro support. To include all electricity savings from codes and standards in the cost-effectiveness analysis would provide an inaccurate assessment of the cost-effectiveness of electricity savings resulting from BC Hydro’s DSM expenditures.

BC Hydro’s expenditures in support of codes and standards are justified on the grounds that they are cost-effective if only one per cent of the DSM Plan’s codes and standards savings are attributable to BC Hydro’s efforts. BC Hydro is confident that its expenditures in support of codes and standards will be critical to the achievement of considerably more than one per cent of the Plan’s codes and standards savings.

Further details concerning the cost/benefit analysis are set out in section 4 of the DSM Plan, attached as Appendix K.

The implementation of the DSM Plan is justified for the following reasons:

- It is aligned with B.C. Government policy, and is compliant with sections 1 and subsections 44.1(2) and 44.1(4) of the UCA. As set out in Chapter 1, Table 1-2, BC Hydro will meet 78 per cent of its incremental resource needs through DSM by 2020, and with a DSM target of 11,500 GWh/year for F2021, BC Hydro will meet 90 per cent of its incremental load growth between F2008 and F2021 through DSM;

- It is low cost and robust under a range of scenarios. The 2008 LTAP portfolio analysis indicates that DSM has a substantially lower cost than new electricity supply. As discussed in section 5.5, DSM Option A would reduce the cost of closing BC Hydro’s load/resource gap by an average of $7.8 billion relative to a supply-only scenario. Also, DSM Option A would deliver electricity savings at an average unit cost of $41/MWh, compared to new electricity supply costing an average of $125/MWh (Table 5-15). The costs of the DSM Plan could double or more (or the benefits could fall by half or more) and it would remain low cost;

- It is comprehensive. There is a broad range of DSM programs included in the DSM Plan which provide customers in virtually all market segments with an opportunity to participate and thereby offset equity impacts; and
• It is flexible. BC Hydro’s DSM Plan can change over time in response to new information on BC Hydro’s resource requirements, the performance of DSM measures and opportunities to save energy.

With respect to the amortization of DSM costs, in section 32 (ii) of the F07/F08 RRA Negotiated Settlement Agreement, BC Hydro committed to review the appropriate amortization period for DSM costs in its next RRA. In BC Hydro’s F09/F10 RRA, BC Hydro proposed to continue amortizing DSM costs over a ten-year period to provide a better matching of costs and benefits for customers and committed to provide further details on the persistence of DSM energy savings in the 2008 LTAP. The average persistence of energy savings from DSM Plan program activity in F2009-F2011 is 11 years. BCUC Order No. G-55-95 provides for an amortization period of up to ten years. BC Hydro is of the view that a ten-year amortization period remains appropriate for DSM expenditures in F2009-F2011 because the resulting energy savings persist for more than ten years.

Continued amortization of DSM costs over a ten-year period combined with planned DSM expenditures in F2009-F2011 will cause the DSM regulatory account balance to grow from $294 million in F2008 to $557 million in F2011.

### 6.2.1.3 Execution and Risk Mitigation

**Execution**

The Federal and B.C. Governments are expected to implement the codes and standards included in the DSM Plan with BC Hydro’s support. BC Hydro plans to continue to implement a RIB rate structure in October 2008 following BCUC approval. BC Hydro also plans to introduce conservation rate structures for general service customers in 2009.

BC Hydro plans to continue implementing a number of ongoing DSM programs and sector enabling activities and to launch a number of new DSM programs. Finally, BC Hydro plans to continue implementing six supporting DSM initiatives.

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73 BC Hydro F09/F10 RRA, Section 6.4.1, page 6-11.

74 Further details on persistence are provided in Appendix K, Sub-Appendix B.
Risk Mitigation

Like other resources, DSM involves both cost and deliverability risks. Cost risk is the risk that the DSM Plan will not deliver the electricity savings at the planned costs. Deliverability risk is the risk that the DSM Plan does not deliver the projected electricity savings within the specified time frame. Cost risk is the lesser of the two risks due to the DSM Plan’s relatively low cost.

There are deliverability risks associated with each major strategic element of the DSM Plan:

Codes and Standards

- Subject to Government approval and implementation, may not apply to all equipment and buildings, may have varying levels of minimum efficiency standards, depend on compliance by consumers, retailers, builders etc.

Rate Structures

- Subject to BCUC approval, can deliver a price signal to different numbers of customers, customer response to price signals is uncertain.

Programs

- Subsequent to BCUC approval, rely on customer participation and rate of savings per participants.

BC Hydro assessed DSM Plan risks by estimating a probability-weighted range of DSM outcomes, by examining past performance and by benchmarking BC Hydro’s DSM target against other jurisdictions:

- Results of the probability assessment described in Chapter 5 indicate that, if the DSM Plan is implemented according to the current design and schedule, then there is a 90 per cent probability of delivering between 7,900 - 12,000 GWh/yr. of electricity savings in F2020.
• BC Hydro’s energy efficiency programs delivered cumulative electricity savings of 1,828 GWh/yr between F2003 and F2007 (five per cent higher than the planned 1,743 GWh/yr) due in part to BC Hydro’s ability to effectively anticipate and manage DSM risks.

• When measured as the annual incremental energy efficiency savings as a percentage of sales, only New York and New Jersey are more aggressive than BC Hydro’s Option B. Refer to section 5.4.4 of the 2008 LTAP and section 5 of Appendix K for additional details.

BC Hydro will manage and mitigate DSM deliverability risks to the extent practicable by tracking a number of key milestones and indicators and implementing several mitigation strategies. The following is a summary list of milestones and indicators.

Codes and Standards

• Government approval of codes and standards.
• Coverage and efficiency level of approved codes and standards.
• Effective date of codes and standards.

Rate Structures

• Coverage of proposed rate structures.
• BCUC approval of rate structures.
• Customer response to rate structures.

Programs

• BCUC approval of proposed DSM expenditures.
• Participation rates.
• Savings per participant.
• Program costs.

Further details and risk mitigation strategies are provided in section 4.4 of Appendix K, and Sub-Appendices D, E and F attached to Appendix K.

BC Hydro will also carry out comprehensive DSM evaluation activities to confirm electricity saving estimates and improve the design and effectiveness of DSM measures. BC Hydro’s DSM planning will consider the inherent flexibility of DSM. For example, if codes and standards or rate structures do not perform as expected, programs may be continued or expanded to achieve overall energy savings targets. BC Hydro reviews and assesses its DSM activities and results on an ongoing basis, and adjusts the level and mix of strategic elements within the DSM Plan as required, based on experience and current market information.

With DSM savings forming an increasing component of BC Hydro’s plan to balance supply and demand, the tracking of how BC Hydro’s load is responding to DSM programs will need to be closely monitored. A key issue will be the methodology used for integrating historical loads with increasing levels of DSM savings into BC Hydro’s load forecasting research and analysis. The load growth models are mostly “top down” approaches at forecasting, and the DSM savings are mostly “bottom up” estimates. Until more work is done to draw precise linkages between these models, additional caution, over and above the quantitative portion of the risk framework, is warranted when using the results for planning purposes.

The following will be addressed:

• Analyzing historical inclusion of realized DSM savings and related changes in usage rates by isolating their impact in load regression analysis from historical factors such as strikes, weather, economic and technology trends;

• Considering the benefits of better integrating aspects of DSM planning with load forecasting analysis through end-use/energy intensity forecasts; and

• Developing early load forecast signposts to identify how DSM programs and new electricity use trends are being reflected in and overall impact on load growth. Other specific load forecast uncertainties include unanticipated classes of load such as electric
powered vehicles, and the possibility of increased fuel switching between natural gas, heating oil and electricity.

Finally, BC Hydro will manage the impact of DSM deliverability risks through the CRPs set out in section 6.4.2.

6.2.1.4 Future Approval Process

The DSM Plan implementation phase will be the subject of on-going BCUC oversight through the LTAP planning cycle and the regulatory review process. For example, BC Hydro will provide the BCUC and intervenors with an updated DSM Plan in the next LTAP, to be filed with the BCUC pursuant to section 44.1 of the UCA two years from the date of the BCUC’s decision with respect to the 2008 LTAP.

Rate structures will be filed with the BCUC for approval pursuant to sections 58 to 61 of the UCA.

6.2.2 Capacity-Focused DSM

6.2.2.1 Order Sought

BC Hydro is requesting a determination pursuant to subsection 44.2(3)(a) of the UCA that expenditures of $0.6 million in F2009 and F2010 required to complete the Definition phase work for capacity-focused DSM (CF DSM) are in the public interest.

6.2.2.2 Justification

The 2008 DSM Plan discussed in section 6.2.1 contains DSM initiatives that generate associated capacity savings (see Table 6-3). Additional capacity savings may be achievable through CF DSM, which targets capacity savings specifically. BC Hydro has identified several CF DSM options that could generate cost-effective capacity savings, but further development work is required before they would be ready for implementation. The purpose of the Definition phase work is to develop an Implementation phase plan for CF DSM.
6.2.2.3 **Execution and Risk Mitigation**

**Execution**

The work plan envisions a one-year period of work in F2009 and F2010 that would include:

- Incorporation of the capacity reduction potential identified in BC Hydro’s 2007 CPR;
- Research on CF DSM programs, initiatives and technologies employed in other jurisdictions;
- Compilation of concepts for CF DSM programs or initiatives, including rate structures such as Time-of-Use and Critical-Peak-Pricing;
- Solicitation of stakeholder feedback on these concepts;
- Analysis on the need for and cost-effectiveness of further DSM capacity savings; and
- Development of an Implementation phase plan for CF DSM.

BC Hydro plans to spend $100,000 in each of the residential and commercial sectors to research CF DSM programs and initiatives in other jurisdictions, identify best practices among winter-peaking utilities, investigate potential participation rates at different incentive levels, investigate trends in the application of SMI to CF DSM and develop an implementation plan for CF DSM in each sector.

In the industrial sector, BC Hydro plans to spend $380,000 to gauge the interest of customers and their suitability for CF DSM, to estimate peak reduction potential and associated costs among these customers, to review CF DSM initiatives in other jurisdictions, to prepare a detailed feasibility study for CF DSM at selected mechanical pulp mills and to develop an Implementation plan for CF DSM in the industrial sector.

**Risk Mitigation**

BC Hydro proposes that only those CF DSM initiatives that pass the Definition phase review will be advanced to implementation. BC Hydro will consult with customers, industry experts,
consultants and other interested parties with respect to its research findings and its proposed CF DSM Implementation plan. The budget for this engagement is $20,000.

6.2.2.4 Future Approval Process

Once BC Hydro has completed the above Definition phase work, it will submit its Implementation phase plan to the BCUC pursuant to subsection 44.2(1) of the UCA.

6.2.3 Burrard

6.2.3.1 Order Sought

BC Hydro is requesting a determination pursuant to subsection 44.2(3)(a) of the UCA that expenditures of $1.6 million of sustaining capital in F2010 required to ensure the short term reliability of Burrard are in the public interest. In addition, as part of BC Hydro’s request for an Order that determines that the 2008 LTAP is in the public interest under subsection 44.1(6)(a) of the UCA, BC Hydro requests that the BCUC endorse BC Hydro’s plan to rely on Burrard for longer term planning purposes for 900 MW of dependable capacity and 3,000 GWh/year of firm energy. The plan to rely on Burrard for 900 MW and 3,000 GWh/year will entail inspection work and additional sustaining capital investments and OMA expenditures consistent with Scenario 2 of AMEC’s report concerning the current condition of Burrard found at Appendix J-1. Additional expenditures associated with the inspection work and sustaining capital/OMA will be the subject of a separate future application to the BCUC as further discussed in section 6.2.3.4.

6.2.3.2 Justification

Need

Burrard continues to play a vital role in providing capacity support to the high load, low resource, and transmission constrained LM/VI region. As discussed in the RWDI Rebuild Burrard permitting analysis report (Appendix J4), there are significant permitting risks associated with siting natural gas-fired facilities in the LM/VI region.
As shown in section 6.4.3 to meet peak load conditions in the LM/VI region, Burrard is required to operate as indicated in Table 6-6.

### Table 6-6 Reliance on Burrard and the CE in the Base Plan and CRPs

<table>
<thead>
<tr>
<th>System Condition</th>
<th>Burrard Reliance (MW)</th>
<th>CE Reliance (MW)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Base Plan Normal</td>
<td>640</td>
<td>0</td>
</tr>
<tr>
<td>Base Plan N-1 T Contingency after 1 hr</td>
<td>900</td>
<td>115</td>
</tr>
<tr>
<td>CRP* Normal</td>
<td>750</td>
<td>400</td>
</tr>
<tr>
<td>CRP* N-1 T Contingency after 1 hr</td>
<td>750</td>
<td>640</td>
</tr>
</tbody>
</table>

* - CRP removes the capacity of one Burrard unit.

Burrard will be required at least until 5L83 is in-service. For purposes of the 2008 LTAP, BC Hydro is planning to meet load requirements under a five-year delay contingency. That would require Burrard to be reliably available at least through F2019. Beyond the ISD of 5L83, BC Hydro expects Burrard will continue to be of value as an energy and capacity plant and plans to continue to periodically review Burrard’s role.

### Cost-Effectiveness

- Given Burrard’s location in the LM/VI region, there are limited alternatives to relying on Burrard without additional transmission to this region. As shown in Table 3-22, the least cost capacity resources are the Mica/Revelstoke units that require 5L83 to transfer dependable capacity to the Lower Mainland. These units are not an alternative to Burrard until 5L83 is in-service.

- After the Mica/Revelstoke units, the next least cost capacity resources in Table 3-22 are natural gas-fired peaking units (SCGTs). These facilities will have permitting risks in the LM/VI region.

- In Figure 5-10, the costs of maintaining Burrard for 900 MW and 3,000 GWh are compared to the options of Rebuilding Burrard with SCGTs. The figure shows that there is no realistic operating point where a new SCGT would be lower cost than maintaining Burrard.
Burrard as currently configured (**Maintain Burrard**). Seeking to rebuild Burrard also raises the risk that Metro Vancouver will require more stringent permitting requirements, especially with respect to start ups and shut downs, which could impact availability. As described in RWDI’s analysis of Burrard’s social license (Appendix J3), Metro Vancouver and other Government entities opposed the proposed 600 MW Sumas Energy 2, Inc. CCGT project on the basis of, among other things, start up emissions of nitrogen oxides were higher than during operation mode.

- Given Burrard’s low cost and the risks associated with other alternatives, Burrard is the most cost-effective resource to meet LM/VI needs until 5L83 is in-service. BC Hydro is of the view that Burrard will continue to play a role as a cost-effective resource after 5L83 is in-service. As a result, BC Hydro will periodically review the role of Burrard.

### 6.2.3.3 Execution and Risk Mitigation

**Business Risk Management**

The key business risk in Maintaining Burrard is ensuring the facility is available as required to meet system needs. The refurbishment work on Burrard must be integrated into the substantial sustaining capital program that BC Hydro already has underway on its generation fleet. Ensuring Burrard’s availability will require the expeditious implementation of the detailed unit inspections, the acquisition of the key spares as identified by the inspections and increasing the maintenance and staffing as identified in the AMEC report attached Appendix J1.

BC Hydro will be developing a project plan in F2009 to implement the AMEC recommendations with expected timelines as follows:

- **F2009** Develop project plan to undertake detailed inspections including tendering and retaining consultants;

- **F2010-F2012** Undertake detailed unit inspections at the rate of two per year. Order of inspections to begin with older and worse condition Units 1-3.
Units 4-6 would follow. This work would include taking key measurements for any critical spares identified in the inspection.

- **F2010-F2012** Procure critical spares (including control system upgrades) as required and as identified in the detailed inspections. Non-critical items would be reflected in capital plans.

**Scope Risks:** Scope risk is limited since the sparing and unit upgrade costs will be driven by the detailed inspections.

**Schedule Risks:** The ability to ramp up the detailed inspections and ensure timely procurement of critical spares will be a concern. In the development of the project plan, BC Hydro will identify the availability of both inspection consultants and manufacturing facilities that are capable and available to design and build appropriate replacement parts for Burrard.

**Cost Risks:** The major cost risks are the number of critical spares required and any costs of other systems identified in the AMEC study that require refurbishment. Mitigation of the cost risks is provided somewhat by the detailed inspections. Should the detailed inspections result in the degree of refurbishment work being more substantial and expensive than anticipated, BC Hydro may have to reconsider the maintain Burrard as currently configured option. Given the limited alternatives and their associated risks, it is unlikely that BC Hydro would materially change the Maintaining Burrard Project plan.

**Resource Risks:** Resource risks are a fairly high risk given the substantial sustaining capital work already underway on BC Hydro’s generating resources. Concerns will be identified in the project plan.

**6.2.3.4 Future Approval Process**

With this application, BC Hydro is asking the BCUC to endorse BC Hydro’s plan to rely on Burrard for longer term planning purposes for 900 MW of dependable capacity and 3,000 GWh/year of firm energy. As indicated on page S4 of the AMEC report at Appendix J-1, this plan is expected to entail sustaining capital expenditures for the years 2010 to 2012 in the range of $55 - $127 million. The precise sustaining capital requirements will depend
on the results of unit condition assessment inspections yet to be undertaken. These expenditures will cover the acquisition of critical spares for the plant and fund the base sustaining capital program identified by AMEC. The scope of work and expenditure range will be further refined in the project plan for which further BCUC determinations will be sought in accordance with future RRAs or other applications. In the interim, costs and commitments needed to ensure Burrard is reliably available in the near term will be managed within the expenditure requested in this Application and BC Hydro's overall generation budget.

6.2.4 Mica Unit 5/Mica Unit 6

6.2.4.1 Order Sought:

BC Hydro is requesting a determination pursuant to subsection 44.2(3)(a) of the UCA that expenditures of $30.0 million in F2009, F2010 and F2011 required to complete the Definition phase work for Mica Unit 5 and Mica Unit 6 (the Mica Units) are in the public interest. BC Hydro is of the view that the benefits realized by completing the Definition phase work for the Mica Units at the same time are in the public interest. These benefits are explained in section 6.2.4.3.

In the 2006 IEP/LTAP BC Hydro committed to ensuring that Revelstoke Unit 6 and Mica Units would be maintained at the appropriate development stage depending on the capacity requirements, transmission upgrade status and expected system benefits. BC Hydro also sought and received a BCUC determination for Identification phase funding to maintain these projects and to determine the appropriate sequence and ISD for the development of these three generating units. As a result of this Identification phase work, BC Hydro determined that the appropriate sequencing of these units is Mica Unit 5 followed by Mica Unit 6 followed by Revelstoke Unit 6. Table 6-7 provides a summary of the energy gain and shaping benefits for each unit and for the three possible sequences to install the three generating units. The sequencing chosen (sequence 3) adds energy gain and shaping benefits sooner to BC Hydro's system, resulting in a larger NPV as compared to the other two alternative sequences.

75 The Definition phase work takes approximately 26 months (minimum), with the Implementation phase taking five+ years.
### Table 6-7 Sequencing Scenarios

<table>
<thead>
<tr>
<th>Sequence</th>
<th>2014</th>
<th>2017</th>
<th>2022</th>
</tr>
</thead>
<tbody>
<tr>
<td>Sequence 1</td>
<td>Mica 5</td>
<td>Rev 6</td>
<td>Mica 6</td>
</tr>
<tr>
<td>Energy Gains (GWh)</td>
<td>134</td>
<td>26</td>
<td>50</td>
</tr>
<tr>
<td>Shaping Benefit ($M/yr)</td>
<td>5</td>
<td>1</td>
<td>1</td>
</tr>
<tr>
<td>Sequence 2</td>
<td>Rev 6</td>
<td>Mica 5</td>
<td>Mica 6</td>
</tr>
<tr>
<td>Energy Gains (GWh)</td>
<td>15</td>
<td>145</td>
<td>50</td>
</tr>
<tr>
<td>Shaping Benefit ($M/yr)</td>
<td>3</td>
<td>4</td>
<td>1</td>
</tr>
<tr>
<td>Sequence 3</td>
<td>Mica 5</td>
<td>Mica 6</td>
<td>Rev 6</td>
</tr>
<tr>
<td>Energy Gains (GWh)</td>
<td>134</td>
<td>50</td>
<td>26</td>
</tr>
<tr>
<td>Shaping Benefit ($M/yr)</td>
<td>5</td>
<td>2</td>
<td>0.5</td>
</tr>
</tbody>
</table>

#### 6.2.4.2 Justification:

**Need**

BC Hydro must continue to advance the Mica Units since these units are important contingency resources. As shown in section 6.4, Mica Unit 5 could be required as a contingency resource in F2014 while Mica Unit 6 is required as a contingency resource in F2016.

**Cost-Effectiveness – Mica Unit 5 and Mica Unit 6**

- Both Mica Unit 5 and Mica Unit 6 would provide very long term (50+ years) dependable capacity\(^76\) (465 MW and 460 MW respectively) to enhance BC Hydro’s ability to reliably meet the winter peak demand. The dependable capacity of the Mica Units is supported by the Kinbasket Reservoir. As such, when required, output can be sustained at the dependable capacity for 16 hours during an extended peak demand period. This makes both Mica Units more reliable sources of dependable capacity than resources that can only sustain output at their dependable capacity for a few HLH per day.

The energy benefits identified in Table 6-7 will offset the capital cost of the Mica Units. The current estimate of these energy benefits was developed in the summer of 2007. As part of

\(^76\) The dependable capacity is less than the installed capacity of approximately 500 MWs due to head losses at Mica. This is because the determination of dependable capacity is based on the Unit's capability in historical low stream flow years when the Kinbasket Reservoir is drawn down during the winter peak demand period.
the Definition phase work to further investigate the Mica Units, the analysis of these benefits will be updated and provided when BC Hydro submits a request to the BCUC for a determination concerning either the Mica Unit 5 Implementation phase or Mica Unit 6 Implementation phase.

With the energy gains in sequence 3 of Table 6-7 valued at $88/MWh combined with the energy shaping benefits, the UCC for the Mica Units\textsuperscript{77} delivered to the Lower Mainland based on the expected loaded costs\textsuperscript{78} of Error! Reference source not found.-set out in Table 6-8 are $34/kW-yr ($2008) and $49/kW-yr ($2008) respectively.\textsuperscript{79}

<table>
<thead>
<tr>
<th></th>
<th>Expected Direct Cost \textsuperscript{80}</th>
<th>Expected Loaded Cost ($M)</th>
<th>High Case Loaded Cost and deferred ISD</th>
</tr>
</thead>
<tbody>
<tr>
<td>Mica Unit 5</td>
<td>316</td>
<td>420</td>
<td>560</td>
</tr>
<tr>
<td>Mica Unit 6</td>
<td>316</td>
<td>420</td>
<td>700\textsuperscript{81}</td>
</tr>
</tbody>
</table>

\textit{Definition Phase Activities and Timeline}

Table 6-9 provides the timeline and Table 6-10 provides the costs for the Definition phase activities. A summary of the Definition phase deliverables are as follows:

- EAC application filed;
- Initiation of the process to obtain Federal environmental approvals;

\textsuperscript{77} The calculation of UCC for Mica Unit 5 includes BCTC’s estimated costs for the capacitor station required to integrate Mica Units 5 and 6.

\textsuperscript{78} Note that the expected and high cost estimates are not based on Monte Carlo simulations. If a Monte Carlo simulation had been completed, then the cost estimate would be referred to as a P50 estimate.

\textsuperscript{79} The UCC calculation includes water rental costs of $6.197/MWh and $3.68/kW ($2008) and are calculated using a 6 per cent discount rate (net of inflation) which is based on a debt/equity ratio for BC Hydro of 70/30.

\textsuperscript{80} The direct $2008 cost for Mica Unit 5 and Mica Unit 6 reported in the December 2007 development of the ROU was $337 million each. This estimate has subsequently been revised to $316 million each; but not in time to update the ROU. This revision does not have a material impact on the portfolio analysis conducted for the 2008 LTAP.

\textsuperscript{81} Mica Unit 6 high case cost estimate includes cost escalations resulting from ISD uncertainty.
1. The application for BCUC approval filed for project implementation;

2. Initiation of consultation with affected First Nations;

3. Updated assessments of the benefits associated with the project;

4. Approved User Requirements documents;

5. Turbine and Generator Contract awarded. Turbine model work and preliminary generator design work initiated. Implementation phase of the contract subject to regulatory and Board approval;

6. Civil infrastructure tender prepared but not issued;

7. Preliminary design work completed for the Generator Transformers, Gas Insulated Switchgear and bus, Generator Terminal Equipment, Exciter, Governor, and P&C requirements;

8. BCTC Interconnection study initiated and Remedial Action Scheme evaluation;

9. Implementation Phase Business Case; and

10. Implementation Phase Project Plan.
Table 6-9  Mica Units Definition Phase Timeline

<table>
<thead>
<tr>
<th>Activity</th>
<th>Target Completion Date</th>
</tr>
</thead>
<tbody>
<tr>
<td>Definition Phase starts</td>
<td>May, 2008</td>
</tr>
<tr>
<td>Phased Turbine tender award(^{82})</td>
<td>May, 2009</td>
</tr>
<tr>
<td>Expected issuance of EAC</td>
<td>February, 2010</td>
</tr>
<tr>
<td>Expected Determination issuance by BCUC</td>
<td>February, 2010</td>
</tr>
<tr>
<td>Definition phase ends</td>
<td>June, 2010</td>
</tr>
<tr>
<td>Mica Unit 5 Implementation Phase begins</td>
<td>June, 2010</td>
</tr>
<tr>
<td>Turbine model tests complete</td>
<td>August, 2010</td>
</tr>
<tr>
<td>Mica Unit 5 In-Service</td>
<td>October, 2013</td>
</tr>
</tbody>
</table>

\(^{82}\) Turbine tender will include flexibility to manage the project timeline given that the Mica Units are contingency resources.
### Table 6-10  Mica Units Definition Phase Costs ($ million)

<table>
<thead>
<tr>
<th>Task</th>
<th>Costs ($M)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Management and Engineering</td>
<td>1.0</td>
</tr>
<tr>
<td>Design, Tender Preparation</td>
<td>2.8</td>
</tr>
<tr>
<td>Turbine Model Test</td>
<td>5.2</td>
</tr>
<tr>
<td>Constructability Plan</td>
<td>0.3</td>
</tr>
<tr>
<td>Quality Management Plan</td>
<td>0.1</td>
</tr>
<tr>
<td>Safety Management Plan</td>
<td>0.05</td>
</tr>
<tr>
<td>Environment Mgmt Plan</td>
<td>0.02</td>
</tr>
<tr>
<td>Regulatory approvals, First Nation Consultation and Stakeholder Engagement</td>
<td>9.5</td>
</tr>
<tr>
<td><strong>Subtotal</strong></td>
<td><strong>19.0</strong></td>
</tr>
<tr>
<td>Reserve for External Project Mgt</td>
<td>2.0</td>
</tr>
<tr>
<td>Contingency</td>
<td>3.2</td>
</tr>
<tr>
<td><strong>Total Direct Cost $2008</strong></td>
<td><strong>24.2</strong></td>
</tr>
<tr>
<td>Inflation</td>
<td>0.8</td>
</tr>
<tr>
<td>Corporate Overhead</td>
<td>3.2</td>
</tr>
<tr>
<td>Interest During Construction</td>
<td>1.7</td>
</tr>
<tr>
<td><strong>Total Definition Phase Cost (Loaded)</strong></td>
<td><strong>$29.9</strong></td>
</tr>
</tbody>
</table>

#### 6.2.4.3 Execution and Risk Mitigation

Business Risk Management

This Definition phase work will maintain the early ISDs of October 2013 for Mica Units 5 and October 2014 for Mica Unit 6. BC Hydro will be seeking future BCUC determinations for the Implementation of Mica Unit 5 and Mica Unit 6. When seeking BCUC determinations for the Implementation phase of the Mica Units, BC Hydro will include details regarding project implementation risks.
BC Hydro is of the view that performing the Definition phase work for both Mica Unit 5 and Mica Unit 6 together is appropriate because: (i) the incremental cost of including definition phase work for Mica Unit 6 is modest83 (approximately $500,000); and (ii) much of the Definition phase work is for engineering work of hydroelectric generator/turbine units, a mature technology, and so this engineering work is expected to have a robust “shelf life”. The environmental review process, stakeholder engagement and First Nations engagement will need to consider the cumulative impacts and issues associated with both Mica Unit 5 and Mica Unit 6 regardless of whether the Definition phase work is for only Mica Unit 5 or for both generating units. As such, there will be minimal cost reductions related to the environmental review process, stakeholder engagement and First Nations engagement if the Definition phase scope was restricted to Mica Unit 5.

Definition Phase Risk Management

Scope Risks: Scope risk is limited since both Mica Unit 5 and Mica Unit 6 are well defined and are to be located in the existing Mica Generating Station.

Schedule Risks: In December 2007, BC Hydro commenced preparation for the environmental assessment review process. In March 2008 BC Hydro submitted a Project Description to the B.C. Environmental Assessment Office (EAO). The Project Description outlines BC Hydro’s process for engaging First Nations and stakeholders with a view to obtaining an EAC pursuant to BCEAA. BC Hydro also confirmed in March 2008 that Mica Unit 5 will be subject to a harmonized Provincial and Federal environmental assessment process lead by the EAO.

A Determination application for Implementation of Mica Unit 5 is expected to be filed with the BCUC at the earliest in 2009 for the project implementation funding. The Determination application will, among other things, articulate project risks, and the associated mitigation plans for the Implementation phase.

Cost Risks: The major cost risks for the Definition phase are related to First Nation consultation and accommodation activities.

83 Incremental work includes civil engineering, surveys and inspections.
Resource Risks: Resource risks are limited because the core of the project team will move from Revelstoke Unit 5 to Mica Unit 5.

6.2.4.4 Future Approval Process

Approval to advance Mica Unit 5 and Mica Unit 6 from the Definition phase to the Implementation phase will be sought by filing Determination applications with the BCUC pursuant to subsection 44.2(4)(1) of the UCA. BC Hydro expects to file a Determination application for Mica Unit 5 project in 2009, followed at some point by a separate Determination application for Mica Unit 6.

6.2.5 Site C

6.2.5.1 Order Sought:

BC Hydro is requesting a BCUC determination pursuant to subsection 44.2(3)(a) of the UCA that expenditures of $41.0 million required to complete Stage 2 (Project Definition Consultation) work for Site C in F2009 and F2010 are in the public interest. A regulatory asset account has been established for these costs pursuant to BCUC Order No. G-143-06.

6.2.5.2 Justification:

As previously described in section 3.3.9, Site C is a potential third hydro-electric facility in the northeast region, and would become a key component of the Peace River generating system. Currently, the existing facilities in the system, the GMS and Peace Canyon Generating Stations, produce approximately one-third of BC Hydro’s annual energy production. As a third generation facility on a one river system, Site C would take advantage of the large amount of water stored upstream in the existing Williston Reservoir. Site C would provide 900 MW of dependable capacity and generate, on average, 4,600 GWh of energy annually.

Based on the range of initial estimates of the capital costs of Site C, the 2008 LTAP analysis suggests Site C is in the range of cost for other potential large hydro resource options. Additionally, a comparative analysis of the ISDs and relative environmental impacts of other potential large hydro resource options, provided in the potential large hydro report at
Appendix F8, demonstrates that further investigation of Site C as a potential resource option is warranted.

Policy Action No. 13 of the 2002 Energy Plan states: “While BC Hydro does not plan to invest in the construction of new hydroelectric facilities at the present time, any proposed new BC Hydro hydroelectric facility, such as Site C, must be brought to Cabinet for approval before being considered by the Utilities Commission as a source of supply”. To complete the analysis in the next phase in evaluating Site C as a potential resource option, BC Hydro needs to continue implementing Stage 2 of a five stage process (Staged Process). The completion of Stage 2 will permit BC Hydro to make a recommendation to the B.C. Government with regard to the next step in the potential development of Site C.

6.2.5.3 Execution and Risk Mitigation:

In the context of the F05/F06 RRA hearing, BC Hydro proposed the Staged Process for the evaluation of Site C. The integral benefit of the Staged Process was that it established incremental decision points in a series of stages of project development. Each stage is designed to expand on the level of scope and commitment from the previous stage. The decision points are strategically placed to facilitate informed decision-making before the potential next step is taken in the Staged Process.

Each stage, excepting Construction, concludes with BC Hydro’s review and analysis of the status of project followed by recommendations to the B.C. Government. Following receipt of the recommendations, the B.C. Government will make a decision as to whether to proceed to the next stage of the process or whether the project should be cancelled or deferred.

The Staged Process currently consists of the following components:

- Stage 1 – Feasibility (complete);
- Stage 2 – Project Definition and Consultation;
- Stage 3 – Regulatory;
- Stage 4 – Engineering; and
• Stage 5 – Construction.

The Staged Process was described in BC Hydro’s 2006 IEP/LTAP as consisting of six stages rather than the current five stages. The Staged Process has since been revised so that Stage 3: Preparation of Environmental Impact and Other Regulatory Applications; and Stage 4: Regulatory Approval Process; described in the 2006 IEP/LTAP, have now been amalgamated into a single Stage 3, Regulatory. In addition, as part of the review of the project plan some elements of Stage 3 have been moved into Stage 2 and are now part of the $41.0 million expenditures. Stage 1 was completed in March 2007 with the approval of Cabinet and a directive to commence Stage 2. A summary of the Stage 1 Review of Project Feasibility is attached as Appendix L1.

The Staged Process incorporates sufficient safeguards to control costs and manage risk. Based on the work undertaken in Stage 2, BC Hydro will provide recommendations to the B.C. Government and it will decide whether to proceed to Stage 3, the Regulatory phase of the project. The completion of Stage 2 is, therefore, an important step in the Staged Process and it will inform the B.C. Government’s decision on the merits of developing Site C as a future energy resource.

6.2.5.4 Future Approval Process and Expenditures:

Stage 2 is currently underway and involves further project definition, including environmental, engineering and socio-economic studies, as well as comprehensive consultation with communities, stakeholders, regulators, First Nations, and discussion with the Province of Alberta and Northwest Territories to better understand the benefits, costs, and impacts of the project. A summary of the work that has been, and will be, carried out in Stage 2 includes:

• Engineering work which includes field investigations to confirm slope stability and foundation conditions; flood and earthquake design criteria; availability of construction material; Highway 29 relocation, safeline review, and mapping;

• Environmental work including field research such as fish tracking, water quality, and wildlife, and the establishment of Technical Advisory Committees;
• Commercial work including preparing a risk registry, procurement options, and reservoir operating analysis

• Third party reviews;

• Updated interim project cost estimate;

• First Nations consultation; and

• Public, stakeholder and community consultation.

A more detailed description of Stage 2 is contained in Appendix L2, entitled “Stage 2: Project Definition and Consultation: Primary Objectives and Key Activities by Task Area”.

In the 2006 IEP/LTAP, an estimate was provided for Stage 2 costs, which at the time was predicted to be $20 million for F2007/2008. Since then, Stage 2 has become significantly more defined, including incorporating more preliminary analysis to be better prepared for a potential future regulatory stage. The Stage 2 expenditures are identified in Table 6-11.
Table 6-11  Site C Stage 2 Expenditures ($ million)

<table>
<thead>
<tr>
<th>Activity</th>
<th>Expenditures (nominal $M)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Project Management</td>
<td>3.2</td>
</tr>
<tr>
<td>Project Management</td>
<td></td>
</tr>
<tr>
<td>Quality Assurance</td>
<td></td>
</tr>
<tr>
<td>Legal</td>
<td></td>
</tr>
<tr>
<td>Project Definition</td>
<td>20.9</td>
</tr>
<tr>
<td>Environmental</td>
<td></td>
</tr>
<tr>
<td>Engineering</td>
<td></td>
</tr>
<tr>
<td>Commercial</td>
<td></td>
</tr>
<tr>
<td>Properties</td>
<td></td>
</tr>
<tr>
<td>Regulatory</td>
<td></td>
</tr>
<tr>
<td>Consultation</td>
<td>9.8</td>
</tr>
<tr>
<td>Public Consultation</td>
<td></td>
</tr>
<tr>
<td>Community Relations</td>
<td></td>
</tr>
<tr>
<td>Communications</td>
<td></td>
</tr>
<tr>
<td>First Nations Consultation</td>
<td></td>
</tr>
<tr>
<td>Accounting</td>
<td>7.1</td>
</tr>
<tr>
<td>Overhead</td>
<td></td>
</tr>
<tr>
<td>IDC</td>
<td></td>
</tr>
<tr>
<td>Contingency</td>
<td></td>
</tr>
<tr>
<td>Inflation</td>
<td></td>
</tr>
<tr>
<td>Total</td>
<td>41.0</td>
</tr>
</tbody>
</table>

1 BC Hydro plans to complete Stage 2 and prepare its recommendations to the B.C.
2 Government for June 2009. Should the B.C. Government decide to proceed to the
3 Regulatory phase in Stage 3, the following major regulatory approvals will be required:
4   • Federal Environmental Assessment under CEAA;
5   • EAC under BCEAA;
6   • CPCN under the UCA;
7   • Water Licence.
6.2.6 Clean Power Call

6.2.6.1 Order Sought

BC Hydro is seeking a BCUC determination pursuant to subsection 44.2(3)(a) of the UCA that expenditures of $2.0 million in F2009 and F2010 to complete the Definition phase work and to implement the Clean Power Call are in the public interest. As part of this determination request, BC Hydro requests that the BCUC endorse: (i) the proposed Clean Power Call target of 5,000 GWh/year of firm energy, (ii) that the energy to be purchased pursuant to the Clean Power Call must qualify as “clean or renewable” in accordance with the B.C. Government’s Clean or Renewable Electricity Guidelines, and (iii) the eligibility requirements for the Clean Power Call.

6.2.6.2 Justification

Volume

The Clean Power Call is intended to meet BC Hydro’s load/resource balance requirements.

The updated load resource analysis in sections 2.4 and 5.6.2 show an energy shortfall of approximately 3,200 GWh in 2016 based on the Mid Load Forecast and after implementation of the proposed DSM Plan. The analysis in Chapter 3 has confirmed that there are no material self-build options which can meet the energy shortfall by 2016. Site C’s earliest ISD is 2019, and the large hydro analysis in section 3.3.11 confirms that no other large hydro option can be in-service before 2019. Further, Resource Smart options are primarily capacity projects; the six additional Resource Smart options that are energy projects together can only provide potentially 259 GWh/year. Therefore, the projected energy shortfall will be sourced from IPP purchases from BC Hydro’s acquisition processes, specifically the Clean Power Call and the two phases of the Bioenergy Call (described in section 6.2.7).

BC Hydro issued a structured RFP on June 11, 2008 targeting to acquire 5,000 GWh/year of firm energy. The targeted acquisition amount would include any EPA which may be awarded to CPC or its subsidiaries for WAX and will be pre-attrition. BC Hydro is using a 30 per cent attrition factor for the Clean Power Call and the two Bioenergy Calls, and therefore the post-
attrition volume of the Clean Power Call for planning purposes is 3,500 GWh/year of firm energy.

Attrition Allowance

As described in section 2.3.6, the rate of attrition from the most recent calls has been significant, and ranges from 23 per cent for the 2002 Customer-Based Generation Call to 66 per cent for the 2002/2003 Green Power Generation Call. The attrition rate for the most recent completed acquisition process, the F2006 Call, currently stands at 48 per cent.

For the F2006 Call energy volumes, BC Hydro estimated an attrition range of 20 to 30 per cent based on historical attrition experience, new attrition risks and development uncertainties. In the award of EPAs for the F2006 Call, BC Hydro assumed an attrition rate of 23 per cent and an outage allowance of 7 per cent. In its 2006 IEP/LTAP Decision, the BCUC accepted BC Hydro’s 30 per cent allowance as a valid assessment of the potential attrition/outage rate and also accepted that the estimate would change as the F2006 Call projects proceeded through their various phases of development. With regard to the Clean Power Call (then called the 2007 Call), the BCUC Panel determined that the attrition allowance should be call-specific and directed BC Hydro, when evaluating the results of the Call, to use its best estimate of the likely attrition factor by taking into account all relevant factors, including (a) the steps it has taken in the conduct of the Call to minimize attrition (b) the technology and location of the projects (c) the experience of the developers/sponsors, and (d) any relevant EPA terms and conditions.  

A January 2006 report entitled “Building a Margin into Renewable Energy Procurements: A Review of Experience with Contract Failure” prepared for the CEC provides support for BC Hydro’s 30 per cent attrition allowance for the Clean Power Call and the Bioenergy Call. The report recommends 20 to 30 per cent additional supply is acquired to reflect attrition. The report cites permitting and site issues, financing problems, capital cost increases, and transmission and interconnection issues as the main causes of contract failure.

84 2006 IEP/LTAP Decision, pages 76 and 164.
For the Clean Power Call, BC Hydro is using an attrition allowance of 30 per cent which is consistent with the upper end of the range estimated for the F2006 Call and the recommended range in the CEC report. Recent call experience has caused BC Hydro’s historical attrition factor to increase due to, among other things, siting/permitting obstacles in the IPP project development process. BC Hydro will continue taking attrition-mitigating steps in its RFP and contracting processes but these measures need to be balanced with potential negative impacts on competition and bid prices.

Clean or Renewable Requirement

Policy Action No. 23 of the 2007 Energy Plan rejects nuclear power as a strategy to meet B.C.’s future energy needs, and has been an element in all recent BC Hydro power procurement processes. In addition, Clean Power Call projects must use “proven” technologies. “Proven” technologies are generation technologies which are readily available in commercial markets and in commercial use (not demonstration use only), as evidenced by at least 3 generation plants generating electrical energy for a period of not less than 3 years, to a standard of reliability generally required by good utility practice. The definition of “proven” is consistent with previous BC Hydro power procurement processes. The reason for this eligibility requirement is that Clean Power Call projects are expected to operate reliably and deliver energy on a consistent basis for the term of the EPA. Non-proven technologies do not provide the level of supply certainty required to enable BC Hydro to meet its load requirements. This requirement means that coal-fired generation with CCS is not eligible for the Clean Power Call. The analysis in section 3.3.6 concluded that coal-fired generation with CCS is not a commercial technology option at the present time.

With these two restrictions in place, BC Hydro faced the choice of:

- Requiring that the energy to be purchased by BC Hydro under a Clean Power Call EPA qualify as “clean or renewable energy” in accordance with the B.C. Government’s Clean or Renewable Electricity Guidelines. This stipulation would result in the exclusion of natural gas-fired generation projects (unless any proponent receives recognition from the B.C. Minister of Energy, Mines and Petroleum Resources as clean or renewable electricity); or
• Structuring the Clean Power Call as an open or “all source” call such that all technologies are eligible, including natural gas-fired generating facilities.

BC Hydro has chosen to require that the energy to be purchased under a Clean Power Call EPA qualify as “clean or renewable energy” in accordance with the B.C. Government’s Clean or Renewable Electricity Guidelines. The reasons, detailed below, include the Chapter 5 portfolio analysis showing clean and renewable energy to be cost-effective, in addition to the significant GHG risk associated with natural gas-fired generation projects.

Portfolio Analysis

In the case of the Clean Power Call, the 2008 LTAP and supporting analysis inform the acquisition process rather than providing a shopping list of resources to acquire. Analysis in this 2008 LTAP relies on generic resources to explore strategic issues, such as the volume of the Clean Power Call, the risks of natural gas-fired generation and the cost-effectiveness of clean, renewable resources.

The portfolio analysis in Chapter 5 supports targeting clean or renewable energy. As described in sections 5.6.3 and 5.6.4, BC Hydro employed two primary types of analysis to evaluate the clean, renewable resources against natural gas-fired generation. The analysis based on optimized resource selection, including perfect foresight, indicated that clean resources were selected in all scenarios, while natural gas-fired resources were generally limited to the low and mid natural gas price scenarios. The Call Commitment analysis indicates that the Clean Call Block is relatively resilient to changing conditions, while the PV of the costs of the simulations of across the 11 portfolios showed the Clean Call Block to be slightly lower than the Open Call Block.

GHG Risk

Policy Action No. 18 of the 2007 Energy Plan requires that new natural gas-fired generation have zero net GHG emissions as soon as section 2 of the Emissions Standards Act comes into force (this Act is discussed in section 4.2). In the F2006 Call, bidders were provided with an option to retain all GHG liability or to transfer some or all of the GHG offset liability to BC Hydro in return for a bid price adjustment. As described in section 4.2, GHG legislation has been adopted by the B.C. Government, and the Government of Canada plans to regulate GHG emissions under CEPA. However, the specific form and timing of both B.C.
and Canadian regulations required to establish a GHG cap-and-trade system and to
address other aspects of GHG regulation are highly uncertain, as are the implications for
new B.C.-based natural gas-fired generators. The highly uncertain GHG regulatory regime
will alter the risk profile of natural gas-fired generators. While BC Hydro assessed GHG risk
within its 2008 LTAP planning process (refer to sections 4.2 and 5.2.2.2, and Appendix G1),
the costs of these GHG developments are uncertain, and the financial risk is both long-term
and potentially far-reaching. As a result, BC Hydro is not prepared to accept any GHG risk in
the Clean Power Call.

From an EPA perspective, inclusion of IPP natural gas-fired generation in the Clean Power
Call process could give rise to the following potential risks:

- Risk that BC Hydro becomes directly liable for a breach by the IPP of GHG requirements.
  Currently, this appears to be a fairly low risk. However, as discussed above, GHG
  regulation and policy continue to evolve;

- Risk that the IPP cannot perform the EPA due to a breach of GHG requirements and/or
  excessive costs associated with GHG compliance. This second risk gives rise to potential
  reputation risks for BC Hydro, energy shortfall risks and/or cost implications for BC Hydro
  associated with actions required to enforce the EPA, and potential insolvency
  proceedings involving the IPP; and

- If BC Hydro were to assume any fuel supply obligation, BC Hydro will bear the cost risk
  associated with carbon taxes on that fuel supply.

BC Hydro considered what contractual and other measures it could take to mitigate against
GHG risk if natural gas-fired generation were to be eligible for the Clean Power Call,
including:

- Due diligence during the project selection process to ensure the proponent is capable of
  managing the GHG risk;

- Cost adders in the evaluation process (to the extent BC Hydro) absorbs GHG risk;
• Flow-throughs of some or all of the GHG costs and risk from the IPPs to BC Hydro. While
  this mitigates the risk that the IPP cannot perform due to GHG compliance costs, flow-
  throughs create cost risk for BC Hydro and this would have to be addressed both in the
  evaluation process (see above) and in a variety of contract provisions to control
  BC Hydro’s risk – e.g. BC Hydro buys the offsets, limits on fuel consumption, etc;

• Requirement for some form of security to ensure performance of GHG obligations. If the
  objective were to reduce the GHG risk to zero, this security would have to be equal to the
  estimated potential GHG liabilities for the Seller for the EPA term. This would likely be a
  very large number. This would likely affect the ability to finance the project. It would
  certainly affect the price of the project;

• Self-help remedies would also likely be required, such as allowing BC Hydro the right to
  step in and purchase GHG offsets on behalf of the IPP and the ability to recover its costs
  from the security (discussed above); and

• Even stronger self-help remedies may need to be required to significantly reduce
  BC Hydro’s exposure to GHG liability, such as allowing BC Hydro the right to step in and
  take over operation of the project. This might allow BC Hydro to control the reputational
  risk, costs (to the extent BC Hydro is absorbing any of the GHG related costs as flow-
  throughs) and/or allow BC Hydro to consider other ways to reduce compliance costs
  rather than exercising the step in right described above. It also allows BC Hydro to
  preserve the supply of energy. However, this type of self-help remedy is very complex to
  put in place. It also raises considerable liability and other risks for BC Hydro.

Inclusion of such provisions would make the Clean Power Call process and EPAs very
complex. BC Hydro’s assessment is that at the present time, the potential benefits natural
gas-fired generation brings are outweighed by the potential costs. BC Hydro will reassess
the GHG risk issue in future calls.

Natural Gas Price Risk

Natural gas-fired generation raises concerns over the volatility of natural gas prices and
uncertainty associated with such cost fluctuations. The recent high level of both natural gas
and electricity price volatility has led to consideration of the value of price stability. A 2003 study states that to hedge natural gas price risk, a utility can either invest in renewable generation (which is immune to natural gas price risk), choose among a number of natural gas-based financial and physical hedging instruments (futures, swaps, options on futures, or some combination thereof; physical hedges include long-term gas supply contracts and natural gas storage), or purchase fixed price natural gas-fired electricity with the electricity supplier taking the natural gas price risk.

In BC Hydro’s Final Argument to the 2006 IEP/LTAP, BC Hydro indicated that it was willing to employ a “cap and collar” regime to share the natural gas price risk with IPPs, but that this option required discussion with customer intervenors and IPPs. While BC Hydro may be prepared to enter into a natural gas price risk sharing arrangement with IPPs in the future, BC Hydro has not pursued this issue at this time due to the expected cost-effectiveness of clean or renewable resources and the decision not to accept any Call-related GHG risk.

Alignment with the 2008 UCA Amendments and 2007 Energy Plan

The Clean Power Call aligns with both section 1 of the UCA which provides that one of the “government’s energy objectives” is to “encourage public utilities to produce, generate and acquire electricity from clean or renewable sources”, and with Policy Action No. 21 of the 2007 Energy Plan, which provides: “ensure clean or renewable electricity generation continues to account for at least 90 per cent of total generation”.

Alignment with other Jurisdictions

BC Hydro analyzed the RFP and other acquisition processes of a number of jurisdictions, as identified in Table 6-12.

---

<table>
<thead>
<tr>
<th>Name of Utility</th>
<th>Competitive Acquisition Process</th>
<th>Date</th>
</tr>
</thead>
<tbody>
<tr>
<td>Northern States Power Company</td>
<td>Request for C-BED Wind Proposals for Less than 20 MW</td>
<td>March 15, 2007</td>
</tr>
<tr>
<td>Northern States Power Company</td>
<td>Request for C-BED Wind Proposals for 20 MW or Larger</td>
<td>March 15, 2007</td>
</tr>
<tr>
<td>Ontario Ministry of Energy</td>
<td>RFP for Renewable Energy</td>
<td>July 12, 2005</td>
</tr>
<tr>
<td>Hydro Quebec Distribution</td>
<td>CFT for Wind Generated Electricity</td>
<td>April 5, 2007</td>
</tr>
</tbody>
</table>

Reviews of these and other acquisition processes lead BC Hydro to conclude that while some U.S. electric utilities target clean or renewable through RFPs to comply with RPS requirements, a number of the utilities reviewed were not the subject to a RPS at the time of their IRP or RFP filings, and planned to add renewables on their own merits (avoidance of GHG and natural gas price risks, cost-effectiveness, etc).  

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6.2.6.3 Execution and Risk Mitigation

Execution

The timeline for the Clean Power Call is as follows:

<table>
<thead>
<tr>
<th>Scheduled Date</th>
<th>Event / Activity</th>
</tr>
</thead>
<tbody>
<tr>
<td>June 11, 2008</td>
<td>Issue of Call RFP</td>
</tr>
<tr>
<td>August 12, 2008</td>
<td>Registration of proponents</td>
</tr>
<tr>
<td>November 25, 2008</td>
<td>Submission of proposals</td>
</tr>
<tr>
<td>January to Mid-April, 2009</td>
<td>Discussions/negotiations with proponents</td>
</tr>
<tr>
<td>Mid-April to June, 2009</td>
<td>Final evaluation and approval of selected portfolio</td>
</tr>
<tr>
<td>June, 2009</td>
<td>Award of EPAs</td>
</tr>
<tr>
<td>August, 2009</td>
<td>Section 71 filing with BCUC</td>
</tr>
</tbody>
</table>

Structured RFP

The Clean Power Call will utilize a structured RFP process, as opposed to a Call for Tenders (CFT). The structured RFP will allow modifications to the preferred terms by the proponents and BC Hydro. Proponents may submit modifications to the specimen EPA in their initial proposals, while BC Hydro can initiate, at its sole discretion, discussions and negotiations with selected proponents after proposal submission. This will allow BC Hydro and project proponents greater flexibility to explore variations and alternatives that offer additional value to BC Hydro and its ratepayers. The structured RFP process will also list certain provisions of the contract where BC Hydro does not intend to consider variations to the specimen EPA. The practice of establishing preferred terms and conditions is consistent with other jurisdictions which publish standard contracts but allow for alterations during the RFP negotiation process. Having a set of preferred terms and conditions will limit the costs of the Call and is necessary given the limited time and resources available for negotiations.

Providing the increased flexibility of a structured RFP also reduces the risk of legal claims that might otherwise arise in the context of a CFT. A CFT creates a pre-award contract that involves legal rights and obligations and potential liabilities for both the party issuing the CFT and the party responding to the CFT. While it is possible to include some flexibility for CFT participants to propose, and even discuss, alternate contract terms and conditions, that
flexibility is constrained by the legal rights and obligations inherent in a CFT process. Finally, BC Hydro's jurisdictional analysis indicates that most jurisdictions structure their power procurement processes as a RFP process rather than a CFT process.

The following summarizes the key eligibility requirements, evaluation criteria, and terms and conditions (which are detailed in the Clean Power Call RFP and Term Sheet in attached as Appendix M).

Key Eligibility Criteria

In addition to the “proven” technologies and the clean or renewable eligibility requirements and the prohibition on nuclear technology addressed above, the following is a list of key eligibility criteria for the Clean Power Call RFP:

- **Project Size:** There is no specified minimum project size. However, the firm energy profile submitted by the proponent must commit the proponent to delivering a minimum of 25 GWh/year of seasonal or hourly firm energy. BC Hydro considers this to be the minimum amount of annual energy that justifies the costs involved in procuring and administering a Clean Power Call EPA. In addition, this constraint limits overlap with the SOP.

- **Project Location:** Projects must be located in B.C. This requirement is consistent with the 2007 Energy Plan's policy of energy self-sufficiency (Policy Action 10). It also reduces the complexity of the evaluation process as it eliminates the need for BC Hydro to assess development and performance risk in light of legal and regulatory requirements in other jurisdictions. In addition, projects that would require BC Hydro to transmit energy to the Lower Mainland through another jurisdiction, including projects in the Fort Nelson service area, are not eligible. This requirement avoids potential complexities in the evaluation process associated with the requirement to assess the costs and risks (from a physical, legal or regulatory perspective) associated with transmitting the energy from the project location to the Lower Mainland.

- **Project Type:** Projects may consist of:

  1. Generating units installed at new green field generating plants, or
  2. Additional generating units installed at existing generating plants, or
3. Existing generating units used in load displacement, provided that the units have not been synchronized with the system since January 1, 2005.

Generation projects with current output under contract through a load displacement or DSM contract with BC Hydro are not eligible. Projects that have received this type of funding are ineligible because they should not be able to receive incentive funding and also full commercial prices for the output.

- **Interconnection**: Interconnection issues in the Clean Power Call will be dealt with in accordance with BCTC’s Open Access Transmission Tariff for a Competitive Energy Acquisition Process. In addition, projects must have a point of interconnection on the integrated BCTC transmission system or BC Hydro distribution system (indirect interconnections are permitted through a private transmission line, a third party utility transmission line or a BC Hydro customer interconnection). This requirement avoids potential complexities in the evaluation process that would arise from a requirement to assess the costs and risks associated with transmitting the energy from the project location to the BC Hydro system.

- **Biomass**: Projects that utilize forest-based biomass for fuel requirements are not eligible. This ensures that projects eligible for the Bioenergy Call are directed to that process and reduces evaluation complexities in the Clean Power Call.

- **Existing Contracts**: None of the capacity or energy from a project that is subject to an existing contract with BC Hydro is eligible unless that contract is lawfully terminated by the proponent shortly after the Clean Power Call RFP is issued. This requirement reduces the risk of bidders exiting contracts awarded in previous BC Hydro power procurement processes to access potentially higher prices in the Clean Power Call process.

- **Firm Energy Limitation during System Freshet**: The energy profile submitted by the proponent must limit firm energy deliveries during system freshet (May 1 to July 31) to not more than 25 per cent of the total annual firm energy amount reflected in the energy profile. A similar restriction was included in the F2006 Call. The constraint on firm energy deliveries during system freshet mitigates the risk that proponents will provide a
disproportionate amount of their firm energy at times when BC Hydro may be most restricted in how much energy it can take into the system.

**Evaluation Criteria**

BC Hydro will review the proposals that satisfy the eligibility requirements described above to determine, in BC Hydro’s sole discretion, the most cost-effective portfolio of proposals. BC Hydro will determine the most cost-effective portfolio based on a comparison of adjusted bid prices and potential consideration of a number of non-price factors. The evaluation criteria and their use in the EPA award stage will be detailed in the section 71 report which will accompany the filing of Clean Power Call EPAs with the BCUC. The bid price adjustments currently contemplated are as follows:

- **Hourly Firm:** For a project that offers hourly firm energy, an adjuster will be deducted from the bid price for evaluation purposes. The amount of the deduction will depend on the tendered profile of monthly HLH firm energy. Based on a recent estimate for BC Hydro’s reference price for capacity, the adjustment for a flat profile of HLH firm energy would be approximately $4/MWh. Including an adjustment for projects offering hourly firm energy is consistent with the approach BC Hydro took in the F2006 Call. However, in the F2006 Call the adjuster did not depend on the profile of the monthly HLH firm energy. BC Hydro has decided to change this approach for the Clean Power Call RFP process to reflect the fact that hourly firm energy has different values for BC Hydro based on the delivery profile for that energy.

- **Wind Integration:** For wind projects, an adjuster will be added to the levelized bid price to reflect the costs of integrating wind into the system. The levelized bid price for a wind project will be increased by $10 per MWh to account for costs such as ramp requirements and ancillary services required to accommodate wind projects on the system.

- **Interconnection and Transmission Impacts:** Levelized bid prices will be adjusted to reflect the costs borne by BC Hydro associated with taking delivery of the energy and moving it through the distribution and/or transmission system. Payment of interconnection costs by BC Hydro represents a change in approach from the F2006 Call. BC Hydro has found that the direct assignment cost estimates contained in the Preliminary Interconnection Studies for projects in the F2006 Call are significantly below the direct assignment cost.
estimates for those projects contained in the more detailed interconnection studies. BC Hydro considers that it will achieve an overall lower cost of power if BC Hydro pays the actual costs of the interconnection rather than leaving the proponents to reflect this cost risk in the energy price. The costs borne by BC Hydro include:

- Interconnection costs associated with interconnection of the project to the BC Hydro system;
- Network upgrade costs associated with transmission of the energy from the project through the transmission system to the Lower Mainland. This may also include regional cut-planes or other specific system reinforcements; and
- Energy losses associated with transmission of the energy from the project through the system to the Lower Mainland.

- **Non-Price Factors:** BC Hydro may consider any of the non-price factors listed in the EPA Term Sheet for the Clean Power Call to determine the most cost-effective portfolio. Examples include the status of First Nations consultation (if required) with respect to Government permits, or any engagement with First Nations; the environmental impacts or benefits; and BC Hydro’s load/resource balance at the time of evaluation. Refer to section 18 of the Clean Power Call RFP, attached as Appendix M. The ability to consider non-price factors such as development and performance risk, approved EPA variations not accounted for in the bid price adjustments, generation technology diversity and other factors listed in the EPA Term Sheet, enables BC Hydro to select the best portfolio taking into account a variety of relevant factors.

**Key Terms and Conditions**

The key terms and conditions of the Clean Power Call EPA are summarized below and are also described in the EPA Term Sheet attached as Appendix M. Note that these are BC Hydro’s preferred terms and conditions, but these may be modified by proponents and BC Hydro during the structured RFP process.

- **Product:** BC Hydro is seeking firm energy in the Clean Power Call RFP process. BC Hydro defines “firm energy” as a volume of energy, with a contractually assured delivery, that a proponent must commit to delivering over a specified period. BC Hydro
will also accept and pay for additional energy in excess of the firm energy commitment. BC Hydro refers to that additional energy as “non-firm energy”. In the Clean Power Call RFP process, proponents may offer either seasonal or hourly firm energy. Seasonal firm energy refers to a volume of energy that the proponent commits to deliver to BC Hydro in a season. Hourly firm energy refers to a volume of energy the proponent commits to deliver to BC Hydro in each hour.

- **Term:** The proponent may select an EPA term of 15 to 40 years from the commercial operation date (COD). In the F2006 Call bidders could select an EPA term of 15 to 40 years, but in 5 year increments only. BC Hydro determined that it could offer additional flexibility to proponents in the Clean Power Call RFP process without significant additional administrative cost or complexity.

- **Commercial Operation Date:** Participants in the Clean Power Call must select a date by which they guarantee to achieve COD between November 1, 2010 and November 1, 2016. Allowing participants to select a guaranteed COD date as late as November 1, 2016 is intended to encourage participation by larger projects that require longer permitting and construction time periods. This is a significantly longer COD “window” than BC Hydro has offered in previous power procurement processes. For projects with multiple generators (e.g. wind farms) BC Hydro has also introduced a mechanism that will permit project proponents to start receiving firm energy payments as phases of the project are complete. The ability for project proponents to complete a project in stages offers advantages to both BC Hydro and developers.

There are several reasons why projects in the Clean Power Call are likely to require longer lead times. The construction industry in B.C. is very tight with intense competition for scarce resources. There are significant lead times for ordering the equipment associated with renewable energy projects such as wind turbines and hydropower machinery. Large clean or renewable projects (over 50 MW) trigger BCEAA and may also trigger CEAA. These environmental assessment review processes can take between 2 to 4 years. Additional permitting requirements add to the lead times. Refer to Table 6-13

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88 E.g., for hydroelectric facilities, East Toba took almost 3 years from the September 2004 pre-application phase to the receipt of the EAC in April 2007. WAX took over 4 years from the pre-application phase in June 2003 to receipt of an EAC in November 2007. For wind projects, to date the timeline has been 2 years; e.g., Bear Mountain pre-application of November 2005 to receipt of an EAC in August 2007.
for a list of permits commonly required for clean or renewable projects. Also, there is a
growing need for permitting agencies to address increasingly complex relationships with
First Nations and escalating public concerns about private power development.

<table>
<thead>
<tr>
<th>Ministry or Agency</th>
<th>Legislation</th>
<th>Permit /Approval</th>
<th>Applicability to Clean or Renewable Projects</th>
</tr>
</thead>
<tbody>
<tr>
<td>Ministry of Forests and Range (MoFR)</td>
<td>Forest Act</td>
<td>Works Permit</td>
<td>All</td>
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<td></td>
<td>Forest Act</td>
<td>Road Use Permit</td>
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<tr>
<td></td>
<td>Forest Act</td>
<td>License to Cut</td>
<td>All</td>
</tr>
<tr>
<td>Ministry of Transportation</td>
<td>Transportation Act</td>
<td>Highways Access Permit</td>
<td>All</td>
</tr>
<tr>
<td>Ministry of Tourism Sports and the Arts</td>
<td>Heritage Conservation Act</td>
<td>Section 12 and 14. Permits for Protection and Investigation of heritage resources</td>
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<tr>
<td>Ministry of Agriculture and Lands</td>
<td>Land Act</td>
<td>Licenses, Leases or Rights of Way necessary for securing land interest for a project</td>
<td>All</td>
</tr>
<tr>
<td></td>
<td>Agricultural Land Commission Act</td>
<td>Permission under Section 25</td>
<td>All</td>
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<tr>
<td>Ministry of Environment</td>
<td>Water Act</td>
<td>Water License – required for diversion of water</td>
<td>Waterpower</td>
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<td></td>
<td>Water Act</td>
<td>Section 9 approval – make changes in and about a stream</td>
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<td></td>
<td>Parks Act</td>
<td>Parks Use Permit</td>
<td>All</td>
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<tr>
<td></td>
<td>Parks Act</td>
<td>Resource Use Permit</td>
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<td>Wildlife Act</td>
<td>Permission under section 4 to use land and resources in a Wildlife Management Area</td>
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<td></td>
<td>Environmental Management Act</td>
<td>Environmental Management Act Permits</td>
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<tr>
<td>EAO</td>
<td>BCEAA</td>
<td>EAC</td>
<td>All</td>
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</tbody>
</table>
### Environmental Attributes:
All proponents are required to transfer all “Environmental Attributes” associated with their projects to BC Hydro. “Environmental Attributes” is broadly defined to include RECs, offsets, credits and other tradable rights arising from the environmental attributes and GHG emissions credits associated with the projects.

BC Hydro is requiring all proponents to transfer the Environmental Attributes to BC Hydro to ensure that BC Hydro acquires all elements of the project that are required now, or in future, for the energy to be considered clean or renewable energy and to eliminate any risk of “double counting” reputational harm and/or marketplace confusion that may arise if BC Hydro claims the energy as clean energy while the proponent sells the Environmental Attributes.
Attributes to other third parties. BC Hydro may also require the Environmental Attributes to meet BC Hydro’s obligations with respect to GHG emissions from its thermal generating facility, or may choose to market the Environmental Attributes in the U.S. and in other markets to the benefit of its ratepayers. Without the Environmental Attributes, the energy to be procured would be considered in most jurisdictions to be “null energy” and not clean or renewable energy. This may also be an issue in B.C., depending on how the 90 per cent target is ultimately measured. For this reason, BC Hydro is of the view that it is inconsistent to run a clean, renewable call and not acquire the Environmental Attributes. Finally, the approach of requiring all Environmental Attributes in a clean or renewable RFP is consistent with virtually every other jurisdiction it reviewed. BC Hydro considers that the most cost-effective manner of acquiring those rights is to purchase them, bundled with the associated energy, in a competitive bidding process where proponents can attach any value they consider appropriate for the combined energy and attributes.

Risk and Mitigation

BC Hydro anticipates that some of the more relevant and probable risks associated with BC Hydro not acquiring the amount of energy targeted in a timely manner include, but are not limited to:

- Receiving an insufficient volume of proposals (amount of energy or number of participants);
- Failure to enter into EPAs with proponents even if a sufficient amount of proposals were received because the final provisions of the EPA could not be agreed upon;
- Proponents withdraw proposals;
- Project development delays or cancellation; and
- Transmission development delays.

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89 Generic energy that has been separated from the Environmental Attributes and is not considered renewable.
BC Hydro’s CRP specifically addressing IPP delivery is discussed in section 6.4. The design of the Clean Power Call has been and continues to be the subject of input from IPPs and other stakeholders such that BC Hydro’s energy requirements can be met while minimizing the likelihood that these risks will occur.

As with virtually every acquisition process, whether in respect of the procurement of power or anything else, BC Hydro will reserve the discretion to award no EPAs and/or terminate the process. Committing in advance to award EPAs regardless of price or other tender terms is not in the interest of ratepayers.

6.2.6.4 Future Approval Process

Awarded EPAs will be filed with the BCUC as “energy supply contracts” pursuant to section 71 of the UCA with a report on the evaluation process and outcome. In the report BC Hydro will set out the cost-effectiveness benchmarks used to assess the results of the Clean Power Call. Such benchmarks may include the following:

1. A generic, green field 250 MW CCGT located in the Kelly Lake/Nicola region, adjusted for location and GHG offsets, with the CCGT base cost based on the data in section 3.3.7 and related RODAT sheets found in Appendix F.

2. The May 2008 results of Hydro Quebec’s October 31, 2005 RFP for 2000 MW of new wind power. Hydro Quebec accepted 15 bids for a total of 2004 MW. The average price offered by the winning bids is $105/MWh in total, broken down as follows: $87/MWh for the wind energy, $13/MWh for transmission and an estimated $5/MWh for balancing services provided by Hydro Quebec.

3. Other recent acquisition processes in the U.S. Pacific Northwest.

BC Hydro is of the view that Site C is not an appropriate cost-effectiveness benchmark for the following reasons: (1) the development of Site C is uncertain, as final approval to proceed rests with the B.C. Government; and (2) Site C cannot be in-service by 2016.
With regard to BC Hydro’s commitment for the Clean Power Call, the expenditure levels will vary depending on the weighted average cost of the EPA awards. At the low end, based on a weighted average bid price of $80/MWh in nominal dollars over an assumed contract life of 25 years, BC Hydro’s total commitment would be $10 billion. If the nominal average bid price is $110/MWh, BC Hydro’s total commitment for the Clean Power Call could be as high as $14 billion.

6.2.7 Bioenergy Call

The Bioenergy Call for Power is guided by the policy actions contained in the Province’s 2007 Energy Plan (Policy Action No. 31) and the Bioenergy Strategy. BC Hydro is planning a two-phase call for power to utilize wood infected by the mountain pine beetle as well as other wood fibre fuel sources. The Bioenergy Call will assist in enabling B.C. to be electricity self-sufficient, and allow BC Hydro to meet its resource needs through securing firm, clean energy.

BC Hydro is not seeking any BCUC endorsement or order with respect to the two Bioenergy Calls in the 2008 LTAP. For each of the two phases of the Bioenergy Call, BC Hydro is targeting approximately 1,000 GWh/year of firm energy. With an assumed attrition factor of 30 per cent, the Bioenergy Call is expected to contribute a total of 1,400 GWh/year of firm energy to BC Hydro’s load resource balance by F2016 when the awarded projects are expected to be fully in service. This contribution is reflected in section 6.3, which depicts the load/resource balance that will result from a successful implementation of the 2008 LTAP.

6.2.7.1 Execution

Phase I is for forest-based biomass projects that are immediately viable and do not need new tenure from the MoFR. The Phase I RFP was issued February 6, 2008. Projects may be green field generation or undertaken by customers to utilize biomass in the generation of electrical energy. Eligible projects must use proven technologies, qualify as “clean or renewable” in accordance with the Province’s Clean or Renewable Electricity Guidelines and must be interconnected to the BC Hydro/BCTC system. The specimen EPA allows

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90 Issued January 31, 2008; www.eneenergyplan.gov.bc.ca/bioenergy/.
bidders to sell of a term ranging from 5 to 20 years with all projects required to reach COD by no later than November 2012. Under the flexible RFP process, proponents can submit variations to the standard EPA which may result in negotiations for those proposals that enhance the cost-effectiveness to BC Hydro.

Phase II of the Bioenergy Call will be informed by the ongoing biomass inventory and forest tenure analysis which currently being completed by the MoFR. BC Hydro is planning to release Phase II of the Bioenergy Call during the summer of 2008.

6.2.7.2 Future Approval Process

Awarded EPAs will be filed with the BCUC as “energy supply contracts” pursuant to section 71 of the UCA.

6.2.8 Future Calls

At this juncture, beyond the Clean Power Call and two phases of the Bioenergy Call BC Hydro does not have any specific plans in the next 2 to 3 years to acquire additional energy from IPPs and other third party suppliers via competitive acquisition processes. However, the plans for future calls may change based on revisions to BC Hydro’s load/resource balance outlook, actual attrition experience and other factors that may arise.

6.2.9 Fort Nelson

BC Hydro supplies electricity for the Fort Nelson area from a combination of the Fort Nelson natural gas-fired plant FNG, a 47 MW SCGT, and via a 144 kV transmission line from the Rainbow Lake area of Alberta. Currently, BC Hydro’s customer demand can only be met through a combination of transmission must run (TMR) operation and a large block of curtailable load.

BC Hydro relies on the Alberta system for back-up, but as part of the agreements for this back-up service, BC Hydro is obligated to participate in transmission system protection schemes for the Fort Nelson and Rainbow Lake region. Because of this obligation, there may be times BC Hydro must curtail load in B.C. even though the FNG is fully capable of meeting the BC Hydro customer load.
6.2.9.1 Order Sought

BC Hydro applies for a BCUC Order which determines that expenditures of $59 million in F2009, F2010 and F2011 to complete the Definition phase work for, and Implement phase of the FNGU project is in the public interest under subsection 44.2(3)(a) of the UCA.

BC Hydro seeks a determination from the BCUC that the expenditure of approximately $140 million to complete the Definition phase and Implementation phase of FNU3 is in the public interest under subsection 44.2(3)(a) of the UCA.

In the alternative, BC Hydro seeks determination from the BCUC that the expenditures of approximately $94.5 million to complete the Definition phase and Implementation phase of FNU2 are in the public interest under subsection 44.2(3)(a) of the UCA.

6.2.9.2 Justification

New Energy and Capacity in Fort Nelson

The Fort Nelson area has supply concerns which need to be addressed in the near future. As detailed in section 5 of the revised and updated version of the 2008 FN RP/LTAP (Appendix N1, Exhibit B-1-10), new supply is urgently required to serve BC Hydro’s customer demand in the Fort Nelson region under any scenario of future load growth analyzed.

The current shortfall in available capacity that creates the need to have some load being served on a curtailable basis may be a short term issue. However, the need for must run generation at Fort Nelson will remain at least until some new supply solution is put into service under every expected scenario of future customer demand.

BC Hydro cannot stop relying on Alberta under any scenario for several years, likely at least through 2013. Arrangements will have to be made to ensure this supply continues to be available.

There will likely be load growth beyond the BC Hydro 2007 Reference Load Forecast. As a result, BC Hydro is of the view that the Low Scenario is the prudent minimum load growth profile on which to commit to the implementation of resources that provide incremental
supplies of capacity and energy; and the possibility of load growth materially above the Low Scenario is sufficiently likely in the near to mid term that it is prudent to advance contingency resource options through the Investigation and Definition phases so that the lead time to execute such options. Given the likelihood of this incremental load growth, it is prudent to acquire new supplies. The combination of the AESO transmission Option A1 and the FNGU project appears to be the portfolio that is either the most cost-effective across the range of load forecast scenarios or the common building block before acquiring additional supply resources.

Fort Nelson Generating Station Upgrade Project

With respect to FNU3 Upgrading the Fort Nelson generating station, currently a SCGT, to a CCGT will add an additional 8 to 17 MW (nominal 12.46 MW (annual average conditions) of firm electricity supply in the Fort Nelson area. This $59 140.1 million project could be operational by March 2012 November 2011 if BC Hydro receives a BCUC
With respect to FNU2, upgrading the Fort Nelson generating station, currently a SCGT, to a CCGT will add an additional 8.6 MW (annual average conditions) of firm electricity supply in the Fort Nelson area. This $94.5 million project could be operational by November 2011. BC Hydro is of the view that this project is not only economic, but also is needed as soon as practicable as a result of the supply shortage in the Fort Nelson area. Current details on this project are provided in the revised and updated version of Appendix N2 (Exhibit B-1-10).

6.2.9.3 Execution and Risk Mitigation

**FNU3 and FNU2 Project**

FNU3 results in an additional 24.6 MW (annual average conditions) of plant capacity. BC Hydro is of the view that the project risks will be manageable and the project will be in the public interest. Refer to section 2.8 of Appendix N2 for a description of FNU3 and FNU2 project risks.

**Contingency Plan for New Energy and Capacity in Fort Nelson**

As a result of the scenario modeling in the 2008 FN RP/LTAP, BC Hydro is of the view that it should complete studies for the following activities:

- Investigate expanding the Fort Nelson generating station in addition to the FNGU3 project to a total capacity of approximately 110 MW, effectively doubling the plant’s capability (referred to as the FNG Expansion Project);
- Investigate with the AESO possible transmission supply options in addition to AESO Option A1; and
- Have BCTC complete an Investigation phase review to interconnect Fort Nelson to GMS.

Even if BC Hydro were to commit to the implementation of resources to meet a higher load scenario that the Low Scenario, there are no resources available at this time. Such
Implementation decisions could not occur until the end of 2009 at the earliest. Refer to section 8.3 of the 2008 FN RP/LTAP for additional details with respect to BC Hydro’s contingency plan for meeting additional load after 2012.

**FNGU Project**

The FNGU project will result in an additional 8 to 17 MW of plant capacity. BC Hydro will provide in August 2008 an evidentiary update which will include a +35 per cent/-15 per cent project cost estimate, details on project risks and risk mitigation plans as well as details on other project approvals required. BC Hydro is of the view that based on the information in this evidentiary update, the project risks will be manageable and the project will be in the interests of ratepayers.

**6.2.9.4 Future Approval Process**

**Regulatory Review of FNU3 and FNU2**

BC Hydro’s latest evidentiary update (Exhibit B-1-10) includes revised versions of Appendix N1 and Appendix N2. These appendices have been updated with the latest cost estimate and project details for FNU3 and FNU2, and address many of the Round 2 IRs related to Fort Nelson resource plan, long term action plan and FNU3. The responses to these Round 2 IRs have been filed as Exhibit B-4-2. BC Hydro proposes that the final review of Exhibit B-1-10 as part of the 2008 LTAP oral hearing is appropriate.

**Contingency Plan for New Energy and Capacity in Fort Nelson**

After the investigation of the possible Fort Nelson supply options have been completed and a decision on the most appropriate actions has been made, BC Hydro expects to seek a BCUC determination. Since it is not yet known what project(s) will be selected, the exact nature of the BCUC determination that will be sought is not yet known. For example if the
**FNG Expansion Project**

were to be built by a third party, BC Hydro would submit the EPA per section 71 of the *UCA*; however, if the project was constructed as a Resource Smart project then BC Hydro would be seeking a BCUC determination per section 44.2 *(4)(3)(a)* of the *UCA*.

**Fort Nelson Generating Station Upgrade Project**

As noted above, BC Hydro will be submitting in August 2008 an evidentiary update for the FNGU. BC Hydro is requesting one round of IRs to review this evidentiary update. Upon completion of this IR round, BC Hydro will seek to sever the review of FNGU from the 2008 LTAP proceeding and move to a written hearing. BC Hydro is of the view that due to the supply constraints in the Fort Nelson area, the implementation of this project should commence as soon as possible. Therefore BC Hydro seeks a BCUC determination concerning the FNG by the end of November, 2008.

### 6.3 Load/Resource Gap After Execution of 2008 LTAP

The actions identified in section 6.2 provide BC Hydro’s Base Resource Plan (BRP) for meeting its current and future customers’ electricity needs on a reliable and cost-effective basis. This BRP implements the B.C. Government’s 2007 Energy Plan and the legislative requirements listed in section 1.2.3.

BC Hydro proposes to continue using a staged and flexible approach. The actions proposed in the BRP are those that must be committed to to meet BC Hydro’ objectives and the 2007 Energy Plan requirements. As there is a significant amount of uncertainty in terms of: future load requirements, regulations relating to GHG issues and other subject matter both in B.C. and the U.S., and market structure and conditions, decisions not required today have been deferred until the future LTAPs when BC Hydro will have greater clarity on the needs of its customers in future years and the success of current plans in meeting customers’ needs. Future decisions include when and type of future calls to undertake, decisions on when to construct future Mica / Revelstoke units and reliance on Burrard beyond the ISD of 5L83.

The BRP is shown in the following tables and graphs for capacity and energy respectively.
Figure 6-1  Base Resource Plan  
Capacity Load/Resource Balance

<table>
<thead>
<tr>
<th>Fiscal Year (year ending March 31)</th>
<th>Effective Load Carrying Capability (MW)</th>
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</thead>
<tbody>
<tr>
<td>F2009</td>
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<td>15,000</td>
</tr>
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<td>F2028</td>
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</table>

Legend:
- 2007 Load Forecast Range
- Existing and Committed Resources
- Clean Power Call
- BioEnergy Call
- Canadian Entitlement
- Future Resources
- 2007 Mid Load forecast Before DSM with Reserves
- 2007 Mid Load Forecast after DSM with Reserves
### Table 6-14 2007 System Capacity Supply

<table>
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<tr>
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<td><strong>Long Term Acquisition Plan</strong></td>
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<tr>
<td>Existing Purchase Contracts (excluding Alcan 2007 EPA)</td>
<td>650</td>
<td>650</td>
<td>650</td>
<td>650</td>
<td>650</td>
<td>650</td>
<td>650</td>
<td>650</td>
<td>650</td>
<td>650</td>
<td>650</td>
<td>650</td>
<td>650</td>
<td>650</td>
<td>650</td>
<td>650</td>
<td>650</td>
<td>650</td>
<td>650</td>
<td>650</td>
</tr>
</tbody>
</table>

#### Table Notes:
- **Reserves (see footnote)**: BC Hydro's reserves are based on 14% of total supply excluding existing and proposed Alcan contracts and the 400 MW market reliance. Note: values are rounded to the nearest 50 MW.

### Additional Supply Potential
- **Canadian Entitlement**
  - Supply = 150 MW
  - Deficit = 0 MW

### Effective Load Carrying Capability
- **Load after DSM**
  - High Load Forecast before DSM: 11,150 MW
  - Low Load Forecast before DSM: 10,700 MW

- **Demand - Integrated System Total Gross Requirements**
  - High Load Forecast after DSM: 11,050 MW
  - Mid Load Forecast after DSM: 10,850 MW
  - Low Load Forecast after DSM: 10,450 MW

- **Load after DSM**
  - High Load Forecast after DSM: 11,000 MW
  - Mid Load Forecast after DSM: 10,700 MW
  - Low Load Forecast after DSM: 10,400 MW

- **Effective Load Carrying Capability Surplus / Deficit**
  - High Load Forecast: 0 MW
  - Mid Load Forecast: 0 MW
  - Low Load Forecast: 0 MW

### Load Management - Mid Range with Loss Savings
- **Load after DSM**
  - High Load Forecast after DSM: 11,000 MW
  - Mid Load Forecast after DSM: 10,700 MW
  - Low Load Forecast after DSM: 10,400 MW

### Additional Supply Potential
- **Canadian Entitlement**
  - Supply = 150 MW
  - Deficit = 0 MW

### Effective Load Carrying Capability Surplus / Deficit
- **High Load Forecast after DSM**
  - Surplus = -650 MW
  - Deficit = 0 MW

- **Mid Load Forecast after DSM**
  - Surplus = 0 MW
  - Deficit = 0 MW

- **Low Load Forecast after DSM**
  - Surplus = 0 MW
  - Deficit = 0 MW

### Additional Supply Potential
- **Canadian Entitlement**
  - Supply = 150 MW
  - Deficit = 0 MW

### Supply Require Reserves
- **Sub-total**
  - Supply Requiring Reserves (a + b) = 12,150 MW
  - Reserve Footnote: BC Hydro's reserves are based on 14% of total supply excluding existing and proposed Alcan contracts and the 400 MW market reliance. Note: values are rounded to the nearest 50 MW.
Figure 6-2  Energy Load/Resource Balance - Base

- **Fiscal Year** (year ending March 31)
- **Firm Energy Capability (GWh)**
- **2007 Load Forecast Range**
- **Existing and Committed Resources**
- **Clean Power Call**
- **BioEnergy Call**
- **Future Resources**
- **2007 Mid Load forecast Before DSM**

Legend:
- Yellow: 2007 Load Forecast Range
- Gray: Existing and Committed Resources
- Purple: Clean Power Call
- Yellow: BioEnergy Call
- Red: Future Resources
- Gray: 2007 Mid Load forecast Before DSM
- Black: 2007 Mid Load Forecast after DSM
Long Term Acquisition Plan

Table 6-15

2007 System Energy Supply

Operating Planning
F2009

F2010

F2011

F2012

F2013

F2014

F2015

F2016

F2017

F2018

F2019

F2020

F2021

F2022

F2023

F2024

F2025

F2026

F2027

F2028

47,600
3,200
200
0
7,900
100
0
59,000

46,600
3,900
300
0
7,800
700
0
59,200

46,400
2,900
300
100
7,600
2,000
100
59,300

42,600
3,200
300
100
7,100
3,100
300
56,700

42,600
3,200
300
100
7,100
3,100
400
56,900

42,600
3,200
300
100
7,000
3,100
400
56,800

42,600
3,200
400
100
7,000
3,100
400
56,900

42,600
3,200
400
100
7,000
3,100
400
56,900

42,600
3,200
500
100
6,900
3,100
400
56,800

42,600
3,200
500
100
6,700
3,100
400
56,600

42,600
3,200
500
100
6,200
3,100
400
56,100

42,600
3,200
500
100
6,200
3,100
400
56,100

42,600
3,200
500
100
6,200
3,100
400
56,100

42,600
3,200
500
100
6,100
3,100
400
56,000

42,600
3,200
500
100
6,100
3,100
400
56,000

42,600
3,200
500
100
6,100
3,100
400
56,000

42,600
3,200
500
100
6,100
3,100
400
56,000

42,600
3,200
500
100
6,100
3,100
400
56,000

42,600
3,200
500
100
6,100
3,100
400
56,000

42,600
3,200
500
100
6,100
3,100
400
56,000

0
0
0

0
0
0

0
0
0

0
0
0

700
0
0

900
500
0

1,200
2,000
0

1,400
2,500
0

1,400
3,500
0

1,400
3,500
0

1,400
3,500
0

1,400
3,500
0

1,400
3,500
0

1,400
3,500
0

700
3,500
0

500
3,500
0

200
3,500
0

0
3,500
0

0
3,500
0

0
3,500
0

Mica Unit 6

0

0

0

0

0

0

0

0

0

0

0

0

0

0

0

0

0

0

0

0

Site C

0

0

0

0

0

0

0

0

0

0

0

0

0

0

0

0

0

0

0

0

Future Resources

0
0

0
0

0
0

0
700

0
1,400

0
3,200

0
3,900

0
4,900

0
4,900

0
4,900

0
4,900

0
4,900

0
4,900

500
4,700

1,400
5,300

3,100
6,900

6,100
9,600

6,500
10,000

7,100
10,600

(GWh)

Existing and Committed Supply
Heritage Hydroelectric
Heritage Thermal / Market Purchases
Resource Smart
Revelstoke Unit 5
Existing Purchase Contracts (including Alcan 2007 EPA)
F2006 Call
Standing Offer Program
Sub-total

(a)

Proposed New Supply
Bioenergy Call
Clean Power Call
Mica Unit 5

Sub-total

(b)

0
0

Sub-total

(c)

0
0

0
0

0
0

2,500
2,500

2,500
2,500

2,500
2,500

2,500
2,500

1,900
1,900

0
0

0
0

0
0

0
0

0
0

0
0

0
0

0
0

0
0

0
0

0
0

0
0

(d) = a + b + c

59,000

59,200

59,300

59,200

60,100

60,700

62,500

62,700

61,700

61,500

61,000

61,000

61,000

60,900

60,700

61,300

62,800

65,600

66,000

66,500

(e)
(f)
(g)

61,100
59,800
58,600

62,500
60,900
59,200

63,700
61,700
59,800

64,400
62,200
60,000

65,800
63,300
60,800

67,700
65,000
62,200

69,500
66,400
63,400

70,500
67,200
63,900

71,800
68,300
64,800

73,000
69,300
65,500

74,200
70,200
66,200

74,300
70,100
65,900

75,500
71,100
66,600

76,700
72,000
67,300

77,900
73,000
68,100

79,000
73,900
68,700

80,300
74,900
69,500

81,300
75,800
70,100

82,600
76,800
70,900

83,700
77,700
71,600

(h)

800
800

1,700
1,700

2,400
2,400

3,300
3,300

4,200
4,200

5,300
5,300

6,200
6,200

7,100
7,100

8,200
8,200

9,200
9,200

10,100
10,100

10,900
10,900

11,500
11,500

12,000
12,000

12,400
12,400

12,900
12,900

13,400
13,400

13,800
13,800

14,200
14,200

14,500
14,500

(e - h)
(f - h)
(g - h)

60,200
59,000
57,700

60,800
59,200
57,600

61,300
59,300
57,300

61,100
58,900
56,700

61,500
59,100
56,600

62,400
59,700
56,900

63,300
60,300
57,200

63,300
60,100
56,800

63,600
60,100
56,600

63,800
60,100
56,300

64,100
60,100
56,100

63,300
59,200
54,900

64,000
59,500
55,100

64,700
60,000
55,300

65,500
60,600
55,700

66,100
61,000
55,800

66,900
61,600
56,200

67,600
62,000
56,400

68,400
62,600
56,700

69,200
63,200
57,100

Additional Non-Firm Energy Supply
Non Firm / Market Allowance

Total Supply
Demand - Integrated System Total Gross Requirements
2007 High Load Forecast Before DSM
2007 Mid Load Forecast Before DSM
2007 Low Load Forecast Before DSM
Demand Side Management
Option A - Mid Range with Loss Savings

Load after DSM
2007 High Load Forecast after DSM
2007 Mid Load Forecast after DSM
2007 Low Load Forecast after DSM
Surplus / Deficit

F2009

F2010

F2011

F2012

F2013

F2014

F2015

F2016

F2017

F2018

F2019

F2020

F2021

F2022

F2023

F2024

F2025

F2026

F2027

F2028

2007 High Load Forecast Surplus / Deficit

(d - e + h)

0

0

0

-1,900

-1,400

-1,700

-800

-700

-1,800

-2,300

-3,200

-2,400

-3,000

-3,800

-4,800

-4,800

-4,100

-2,000

-2,400

2007 Mid Load Forecast Surplus / Deficit

(d - f + h)

0

0

0

300

1,000

1,100

2,300

2,600

1,600

1,400

800

1,800

1,400

900

100

300

1,300

3,600

3,400

3,400

2007 Low Load Forecast Surplus / Deficit

(d - g + h)

0

0

0

2,600

3,500

3,800

5,300

5,900

5,100

5,200

4,900

6,000

5,900

5,600

5,000

5,500

6,700

9,200

9,300

9,500

Note: Values are rounded to the nearest 100 GWh

BC Hydro 2008 Long Term Acquisition Plan
6-54

-2,700


Table 6-14 and Figure 6-1 shows that:

1. The capacity associated with the DSM Option A contributed a large portion of capacity needs over the planning horizon. In F2017, 1350 MW of capacity needs are met through DSM;

2. Based upon the DSM Option A capacity savings as well as the capacity associated with the expected results of the Bioenergy Calls and Clean Power Call net of attrition, the peak demand requirements will be met until F2026;

3. The forecast peak demand after DSM is expected to drop modestly through F2020 and then increase thereafter;

4. The 400 MW market capacity reliance ends at the end of 2015, resulting in its removal from the load/resource balance in F2016;

5. In the later years beyond F2023, it is assumed that future acquisition processes or additional DSM programs will provide adequate capacity to meet forecast needs; and

6. As a result, in the BRP, the next Mica units will not be required in the 20 year timeframe.

Table 6-15 and Figure 6-2 show that:

1. DSM Option A will make a significant contribution to provide 8,200 GWh of savings in F2017;

2. Based upon the DSM level of energy savings and the expected results of the Bioenergy Calls and Clean Power Call including attrition, there will be a modest surplus of firm energy in F2017 of 1900 GWh relative to a load requirement of 60,000 GWh;

3. The load requirements will be met until F2022 at which point further resources acquisitions or additional DSM programs will be required; and

4. As a result, no future acquisition processes have been identified and this will be addressed again in the next LTAP.
6.4 Contingency Plans

As reviewed in Chapter 5, there are a number of uncertainties and risks that BC Hydro considers in its resource planning and analysis. The major risks are managed either by selecting actions that avoid or minimize risks or, consistent with good utility practice and the BCUC’s Resource Planning Guidelines, by developing contingency plans 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 three manners:

1. Undertake actions in the BRP that minimize exposure to major risks;

2. Develop CPRs to manage supply shortage risks for the BRP; and

3. Develop Transmission Contingency Plans (TCPs) for the major transmission shortage risks associated with the BRP.

In addition, given the fundamental shift in resource plans to be more demand side focused, the resulting moderate load growth and DSM deliverability risk, BC Hydro will be developing a Regional Planning Contingency Plan (RPCP). The RPCP would be intended to address the potential DSM supply uncertainty impacts on the parts of the electric system below the generation and bulk transmission that are more radial in design, including transmission area planning, station planning and distribution planning.

6.4.1 BRP Contingency Plans

The BRP has managed the following risks:
<table>
<thead>
<tr>
<th>Risk</th>
<th>Action</th>
<th>Rationale</th>
</tr>
</thead>
<tbody>
<tr>
<td>Potential High Natural Gas Prices</td>
<td>Significant DSM program</td>
<td>Avoids further exposure to natural gas prices by reducing need for calls and ensuring calls avoid gas projects</td>
</tr>
<tr>
<td></td>
<td>Target clean resources in next calls</td>
<td></td>
</tr>
<tr>
<td>GHG Offset Requirements and Costs</td>
<td>Significant DSM program</td>
<td>Avoids further exposure to GHG offset policies and prices by reducing need for calls and ensuring calls avoid gas projects</td>
</tr>
<tr>
<td></td>
<td>Target clean resources in next calls</td>
<td></td>
</tr>
<tr>
<td>Burrard incapable or not permitted to operate</td>
<td>Limit Burrard energy reliance to 3000 GWh</td>
<td>Burrard capacity is required and by lowering energy reliance 1) reduces risk of technical or social license issues reducing plant availability, 2) is in line with the 2007 Energy Plan and 3) reduces the impact if something goes wrong</td>
</tr>
<tr>
<td>5L83 Timing Construction results in LM/VI shortages</td>
<td>Maintain Burrard for 900 MW of capacity and retain CE as a contingency resource</td>
<td>Provides maximum available capacity in the LM/VI region without targeting further and potentially expensive capacity additions</td>
</tr>
<tr>
<td></td>
<td>Investigate the potential for cost effective DSM capacity programs or curtailable load</td>
<td></td>
</tr>
</tbody>
</table>

6.4.2 CRP Contingency Plans

CRPs identify alternative sources of supply that could be available should the BRP not materialize as expected. The CRPs aim to advance the development of alternative resources to reduce the lead time to being placed in service if the need for the resource arises. If the advanced ISDs are not planned for and maintained, the contingency will be ineffectual.

To minimize the costs of CRPs, BC Hydro seeks to maintain an advanced ISD by moving a resource through the Investigation and Definition phases incurring minimal costs and without committing to construct the resource. However, at some point, if insufficient lead time is available 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.

In a similar fashion, BC Hydro requests the BCUC’s approval to submit the CRP to BCTC in either a NITS application or update so that BCTC will advance or maintain the required transmission facilities that permit the CRP resources to be utilized. Without BCTC formally including the CRPs in its planning processes and ensuring the CRP transmission requirements are being maintained, BC Hydro’s CRPs would be ineffectual.

In developing the CRPs, BC Hydro considered both capacity and energy shortfall risks. 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 as identified in Table 6-17.
Table 6-17 CRP Shortfall Risks

<table>
<thead>
<tr>
<th>Risk</th>
<th>Rationale</th>
<th>Capacity Reduction for CRP Purposes(^{91}) (MW)</th>
<th>Energy Shortfall Risk (GWh)</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td></td>
<td>F2017</td>
<td>F2028</td>
</tr>
<tr>
<td>Load Forecast Uncertainty</td>
<td>Peak load and energy requirements can increase as a result of either sustained growth or low temperatures on winter peak.</td>
<td></td>
<td></td>
</tr>
<tr>
<td>DSM Deliverability Risk(^{92})</td>
<td>The DSM Plan as modelled has a significant range of deliverability where the variability is driven by implementation of codes and standards, customer response to rate design and rate increases. The DSM Plan delivers both energy and capacity savings – refer to Table 6-2 and Table 6-3 above.</td>
<td>230</td>
<td>380</td>
</tr>
<tr>
<td>Burrard Unit Catastrophic Failure</td>
<td>Given the condition of the units, some units could suffer catastrophic failure, notwithstanding the planned refurbishment work and procurement of critical spares to reduce down time. As a result, one Unit of Burrard was removed for CRP purposes.</td>
<td>150</td>
<td>150</td>
</tr>
<tr>
<td>Calls Capacity Reduction</td>
<td>Based upon less Bioenergy projects being successful.</td>
<td>50</td>
<td>n/a</td>
</tr>
<tr>
<td>Total Reduction</td>
<td></td>
<td>9301,030</td>
<td>4,1901,580</td>
</tr>
</tbody>
</table>

The actions that BC Hydro undertakes as a result of the risks identified in Table 6-17 and the associated capacity gap increases are to advance the lowest cost capacity resources available to BC Hydro and its customers. Based upon an expected ISD of 5L83 in October 2014, the least cost resources available to meet load requirements in B.C.,

\(^{91}\) An additional potential capacity contingency that will be further addressed in future applications is the reliance upon intermittent resources for dependable capacity. As shown in Appendix F12, intermittent resources have an estimated capacity contribution based upon their probability of occurrence under peak load conditions. Both as BC Hydro gains experience in the operation of intermittent resources (wind) and as the penetration of intermittent resources grows (currently are committing to approximately 1,050 kW-MW of existing, contracted or target clean resource capacity by 2020), BC Hydro will need to assess the extent to which the capacity materializes and the ability to utilize the capacity on an operational basis.

\(^{92}\) Additional deliverability risk around DSM capacity savings has been factored into CRPs #1 and #2. The low band of DSM option A has been marginally reduced over the 20-year period by 65 MW in F2020. This was calculated by examining high, medium, and low capacity factor scenarios for each of the main sales sectors residential, commercial and industrial. See Appendix F14 for a further description.
including the LM/VI region, are the next Mica and Revelstoke units. The impact of the CRP results in a portfolio with the following Mica ISDs:

<table>
<thead>
<tr>
<th>Unit</th>
<th>BRP</th>
<th>CRP #1</th>
</tr>
</thead>
<tbody>
<tr>
<td>Mica 5</td>
<td>Not Required</td>
<td>F2014</td>
</tr>
<tr>
<td>Mica 6</td>
<td>Not Required</td>
<td>F2016</td>
</tr>
</tbody>
</table>

The portfolio associated with CRP#1 that would be provided to BCTC is shown in Appendix O. Any energy shortfalls that would occur as a result of the BRP supply risks would be managed as follows:

<table>
<thead>
<tr>
<th>Action</th>
<th>Description</th>
</tr>
</thead>
<tbody>
<tr>
<td>Short lead time acquisition processes</td>
<td>BC Hydro would seek to undertake shorter lead time acquisition processes that could include pre-qualification of bidders and pre-established acquisition rules</td>
</tr>
<tr>
<td>DSM Program Adjustment</td>
<td>The DSM programs identified have an ability to adjust the timing and rate of delivery of energy savings.</td>
</tr>
<tr>
<td>Market Reliance</td>
<td>In the case of a short term shortfall of energy, BC Hydro would ultimately resort to market energy acquisitions.</td>
</tr>
</tbody>
</table>

Alternatively, Site C is an option that provides both dependable capacity and firm energy but is subject to direction from the B.C. Government that BC Hydro can pursue the construction of this resource. To maintain Site C as a feasible option, it is included as CRP #2. CRP#2 is the impetus for BCTC to consider the transmission requirements associated with maintaining Site C as a feasible option. The resulting timing of CRP#2 is as follows:

<table>
<thead>
<tr>
<th>Unit</th>
<th>BRP</th>
<th>CRP #2</th>
</tr>
</thead>
<tbody>
<tr>
<td>Site C</td>
<td>Not Required</td>
<td>F2019</td>
</tr>
<tr>
<td>Mica 5</td>
<td>Not Required</td>
<td>F2014</td>
</tr>
<tr>
<td>Mica 6</td>
<td>Not Required</td>
<td>F2016</td>
</tr>
</tbody>
</table>

The portfolio associated with CRP#2 that would be provided to BCTC is shown in Appendix O.

6.4.3 Transmission Contingency Plans

The TCPs are intended to address the key transmission shortages that impact BC Hydro’s resource plans. The key transmission shortage that faces BC Hydro currently is the 5L83
path. There do not appear to be any other transmission sections that would cause BC Hydro supply concerns in the next ten years. In section 2.5.2, the load resource balance for the LM/VI region was provided. This load resource balance was based on 5L83 being in-service in 2014.

The TCP addresses the impact of a delay in 5L83’s in-service date both under the BRP and the CRPs. The key variable resources that BC Hydro relies upon to meet LM/VI resource requirements are Burrard and use of the CE. Table 6-21 and Table 6-22 show the amount of reliance upon firstly Burrard and secondly CE based upon the following assumptions:

- All other LM/VI region generation is fully available to operate on peak;
- The ILM grid is fully loaded; and
- 5L83 is not available.

93 The Vancouver Island Transmission Reinforcement transmission line is expected to be on line this year as planned and certainly within the operational timeframe, hence, for planning purposes the supply to VI is not currently considered a long term planning concern.
<table>
<thead>
<tr>
<th></th>
<th></th>
<th></th>
<th></th>
<th></th>
<th></th>
<th></th>
<th></th>
<th></th>
<th></th>
<th></th>
</tr>
</thead>
<tbody>
<tr>
<td>2007 Mid Load Forecast LM/VI before DSM</td>
<td>8223</td>
<td>8316</td>
<td>8407</td>
<td>8484</td>
<td>8555</td>
<td>8685</td>
<td>8772</td>
<td>8917</td>
<td>9059</td>
<td>9205</td>
</tr>
<tr>
<td>DSM Savings</td>
<td>381</td>
<td>502</td>
<td>630</td>
<td>734</td>
<td>859</td>
<td>999</td>
<td>1134</td>
<td>1267</td>
<td>1380</td>
<td>1464</td>
</tr>
<tr>
<td>Net Peak Load Forecast</td>
<td>7842</td>
<td>7814</td>
<td>7777</td>
<td>7750</td>
<td>7696</td>
<td>7686</td>
<td>7638</td>
<td>7650</td>
<td>7679</td>
<td>7741</td>
</tr>
<tr>
<td>LM/VI Dependable Capacity (excluding Burrard)</td>
<td>1822</td>
<td>1837</td>
<td>1885</td>
<td>2122</td>
<td>2122</td>
<td>2155</td>
<td>2155</td>
<td>2155</td>
<td>2155</td>
<td>2155</td>
</tr>
<tr>
<td>ILM Transfer Capacity Rating</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>- With all circuits in-service (N-0)</td>
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### Table 6-22 Contingency Resource Plan

Contingency Resource Plan - LM/VI Capacity Balance with 5L83 delayed (MW)

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<td>8869</td>
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<td>864</td>
<td>987</td>
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<td>1873</td>
<td>2036</td>
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<td>- With all circuits in-service (N-0)</td>
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<td>5558</td>
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<td>310</td>
<td>253</td>
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</table>
Table 6-21 shows the BRP case and demonstrates that, in addition to all other resources being available in the LM, Burrard would be relied upon for as much as 610 MW of dependable capacity to meet system requirements under system normal or “N-1” conditions (i.e. no ILM line outages). If there is a “N-1” contingency on the ILM grid, transmission supply to the LM would be reduced by up to 800 MW due to the one hour American Creek Capacitor Bank rating. This would increase reliance on Burrard as Reliability-Must Run (RMR) generation to as much as 905 MW, its full capacity.

Table 6-22 shows the impacts of the CRPs on the LM/VI supply assuming 5L83 is delayed by five years to 2019, and no other ILM upgrades are implemented. In this situation, Burrard is assumed to have one unit unavailable such that the total available capacity is 754 MW. Under system normal or “N-1” conditions, Burrard would supply 330-750 MW over the ten year period. Under an ILM “N-1” contingency, Burrard would be required for its full 754 MW as RMR generation throughout the period and the CE would be relied upon as much as 640 MW.

In both cases, the DSM Plan is holding the load fairly flat and other resources expected from the acquisition processes are reducing the reliance upon the CE and there is adequate CE available to meet load.

Ultimately, if it became apparent that the generation resources and transmission capability to the LM/VI region were inadequate, BC Hydro would need to investigate additional capacity resource options. The available capacity options in the LM/VI region could include additional DSM capacity products as envisioned in section 6.2.2 and, as per section 3.3.14, Table 3-22, pumped storage and new natural gas-fired generation.