BC hydro

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BC HYDRO – 2008 LTAP
EXHIBIT B-10

December 22, 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)

Enclosed as Exhibit B-10 is the Evidentiary Update to the 2008 LTAP.

For further information, please contact the undersigned.

Yours sincerely,

Craig Godsoe
on behalf of

Joanna Sofield
Chief Regulatory Officer

Enclosure (1)

c. BCUC Project No. 3698514 (2008 LTAP) Registered Intervenor Distribution List.

2008 Long-Term Acquisition Plan Application

BC hydro

Evidentiary Update

December 22, 2008

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Attachment 2 - Clean Power Call RFP.

Attachment 3 - Copy of the Canadian Association of Petroleum Producers (**CAPP**) letter of December 15, 2008

Attachment 4 - Copy of the Proposed Capital Plan Review Process- December 10, 2008

Attachment 5 - Copy of OIC No. 849/2008.

Attachment 6 - BC Hydro’s updated CRPs.

1 Introduction and Structure of Evidentiary Update

British Columbia Hydro and Power Authority (**BC Hydro**) files this Evidentiary Update to its 2008 Long-Term Acquisition Plan (**LTAP**) pursuant to British Columbia Utilities Commission (**BCUC**) Order No. G-178-08.[1] This Evidentiary Update is required to address recent economic events and the resulting impacts on BC Hydro's load forecast and Demand Side Management (**DSM**) Plan. In addition, key items that impact BC Hydro commitments to resource acquisition activities have been updated, including expected results of the Bioenergy Call Phase I Request for Proposals (referred to as the **Phase I RFP**) and current attrition estimates for the F2006 Call for Tenders (**F2006 Call**)[2]. The result is a revised Order sought, as set out in Attachment 1 to this Evidentiary Update.

The structure and content of the Evidentiary Update is summarized below.

Part 2 sets out BC Hydro's amended Base Resource Plan (**BRP**) for the BC Hydro Integrated System, and provides new load forecast and other information with respect to the Fort Nelson region. The first portion of Part 2 (sections 2.1 – 2.3) establishes a new load/resource balance for the BC Hydro Integrated System before the actions of the 2008 LTAP:

- Section 2.1 provides a comparison of the 2008 energy and peak load forecasts to the 2007 Load Forecast.[3] section 2.1 also describes BC Hydro's electrification scenario analysis;

- Section 2.2 updates the attrition numbers for the F2006 Call. There are also attrition adjustments to two prior power acquisition processes, the 2002/03 Green Power Generation Call and the 2002 Customer-Based Generation Call; and

- Section 2.3 sets out the resulting updated load/resource balance for the BC Hydro Integrated System before the actions of the 2008 LTAP.

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1 Exhibit A-12.

2 Exhibit B-4, BC Hydro response to BCUC Information Request (**IR**) 1.183.1, provided an update with respect to the Standing Offer Program (**SOP**). The response indicates that four SOP applications had been received by the October 15, 2008 filing date of the IR response. As of December 22, 2008, BC Hydro has received eight applications representing approximately 200 GWh/year of energy. BC Hydro is making no adjustment to the inclusion of 400 GWh/year of energy and 50 MW of dependable capacity in the supply stack in F2013, as shown on Table 6-15, page 6-54, of Exhibit B-1.

The second portion of Part 2 (sections 2.4 – 2.7) updates the 2008 LTAP action items for the BC Hydro Integrated System in light of the updated load/resource balance:

- Section 2.4 describes changes to the expected savings from the DSM Plan. In addition, the impact of new information on the timing of changes to the Federal and British Columbia (**B.C.**) Governments' proposed incandescent lighting regulations are discussed in this section;

- Section 2.5 sets out the Phase I RFP award volume in gigawatt hours per year (**GWh/year**) and megawatts (**MW**);

- Section 2.6 explains the rationale for BC Hydro's request for an amendment to the Order sought to reduce the Clean Power Call pre-attrition target to 3,000 GWh/year. This section also describes the reasons why BC Hydro is of the view that a reduction to a pre-attrition target of 3,000 GWh/year will not impact the competitive nature of the Clean Power Call RFP process. Finally, as described in section 2.6, BC Hydro proposes to use an attrition allowance of 30 per cent for the Clean Power Call, with the result that the post-attrition volume of the Clean Power Call for planning purposes is 2,100 GWh/year; and

- Section 2.7 contains an amended BRP for the BC Hydro Integrated System, and provides and update to BC Hydro's two Contingency Resource Plans (**CRPs**).

Finally, the third portion of Part 2 (section 2.8) consists of a new load/resource balance for the Fort Nelson region and describes additional developments related to Fort Nelson.

Part 3 provides the reasons why BC Hydro is no longer seeking BCUC endorsement of the residential Low Income DSM program as part of its Order sought as a result of the newly enacted *Demand-Side Measures Regulation*[4] (**DSM Regulation**). Part 3 also summarizes how the DSM Regulation changes the All Ratepayers Test (referred to as the **Total Resource Cost** or **TRC Test** in this Evidentiary Update) benefit-cost ratio for BC Hydro's proposed residential Low Income DSM program.

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[3] Exhibit B-1-1, Appendix D to the 2008 LTAP.

[4] B.C. Reg. 326/2008, Ministerial Order No. M217, deposited November 7, 2008. A copy of the DSM Regulation is attached to Exhibit A-10, BCUC IRs to the British Columbia Sustainable Energy Association and Sierra Club of British Columbia.

Part 4 sets out BC Hydro's proposed capital plan review process, including a brief overview of the workshop held for intervenors on 10 December 2008 and the proposed changes to the Order BC Hydro is seeking.

Part 5 updates the 2008 LTAP review of the B.C. Government legislative and policy context with a brief description of Order in Council (**OIC**) No. 849/2008,[5] which establishes the Heritage Contact in perpetuity.

The attachments to the Evidentiary Update are:

- **Attachment 1** contains a revised draft of the requested final Order.
- **Attachment 2** contains information concerning the 68 proposals from 43 registered proponents BC Hydro received on November 25, 2008 in response to the Clean Power Call RFP.
- **Attachment 3** is a copy of the Canadian Association of Petroleum Producers' (**CAPP**) letter of December 15, 2008 entitled "Electric Load Potential Forecast for Horn River Basin Shale Gas in Support of Ft. Nelson LTAP" (**CAPP Forecast**), containing CAPP's forecast of natural gas production and the associated expectation for electricity demand for the Horn River Basin portion of the Fort Nelson region.
- **Attachment 4** is a copy of the proposed capital plan review process-related materials from the December 10, 2008 intervenor workshop.
- **Attachment 5** is a copy of OIC No. 849/2008.
- **Attachment 6** is BC Hydro's updated CRPs.

2 Amended Base Resource Plan for Integrated System

2.1 2008 Load Forecast Update

BC Hydro produces a yearly forecast update of energy and peak load requirements. In accordance with this forecast cycle, this section provides an overview of the updated load forecast, described as the **2008 Load Forecast Update**. The 2008 Load Forecast Update

5 B.C. Reg. 335/2008, deposited November 28, 2008.

includes an updated energy and peak demand forecast for all years through F2028 for the total BC Hydro Integrated System, Non Integrated Areas (**NIAs**) and the Fort Nelson region. The updated Fort Nelson region load forecast is described in section 2.8 of this Evidentiary Update.

The 2008 Load Forecast Update does not introduce significant methodological changes relative to the 2007 Load Forecast filed as Appendix D in the 2008 LTAP. BC Hydro undertakes a sector by sector analysis of load, and this approach was used in the 2008 Load Forecast Update from both the perspective of forecast drivers and forecast models.

2.1.1 Overview of the 2008 Load Forecast Update

The key assumptions behind the 2008 Load Forecast Update include updated forecasts of the key economic drivers used in the load forecast models, revised industrial customer production forecasts and expectations for large industrial customers. [6] The 2008 Load Forecast Update also contains updated forecasts of electricity rate changes and their impact on the load. Possible significant load changes that could result from widespread electrification and electric vehicles have not been factored into the 2008 Load Forecast Update. A high-level description of these scenarios, and an estimation of their possible load impacts, is described in section 2.1.3.

The 2008 Load Forecast Update includes an economic forecast which incorporates quarterly projections provided by the Conference Board of Canada in late October 2008, such as Gross Domestic Product (**GDP**), employment and retail sales. The Conference Board's late October 2008 economic forecast is the most current available information and is lower than the forecasts available during the summer of 2008, such as the quarterly estimates issued by the B.C. Government. Updates on BC Hydro's industrial sector reflect new information concerning mining and forestry, and revised production estimates in the areas of forestry, mining and the oil and gas sector.

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[6] In the 2007 Load Forecast, a 20-year load projection for the transmission-connected forestry sector customers was prepared and included in the overall forecast. For the remaining transmission sector customers, an individual 11-year account forecast was prepared, and then extended for the final 10 years of the forecast period using a GDP-based regression approach. For the 2008 Load Forecast Update, 20-year individual accounts forecasts were prepared for the following sectors: forestry, wood, coal mining, metal mining, and oil and gas.

Table 2-1 below presents load expectations for the key forecast years. All of the forecasts reflected in the tables in this section include rate increase impacts, but do not incorporate DSM savings.

Table 2-1 Key Characteristics of the 2008 Load Forecast Update Before DSM Savings (Update to Table 2-1 of Exhibit B-1)

Energy Load (GWh/year)	F2008	F2017	F2021	F2027	Change between F2008 – F2027	
					Total % Change	Average Annual Growth Rate (%)
Integrated System	58,735	66,172	68,480	73,847	25.7	1.2
Fort Nelson	171	834	1,003	1,007	489.5	9.8
NIAs (excluding Fort Nelson)	128	131	132	132	3.3	0.2
Total	59,034	67,137	69,616	74,986	27.0	1.3
Integrated Peak Demand (MW)	10,597	11,761	12,241	13,239	24.9	1.2

*Fiscal 2008 values are weather adjusted for peak demand only.

2.1.2 **Comparison to the 2007 Load Forecast**

The 2008 Load Forecast Update for BC Hydro's Integrated System is lower than the 2007 Load Forecast in both long-term peak demand and energy requirements. The primary reasons for this are:

- Lower Historical Sales. BC Hydro's weather-adjusted actual sales in F2008 were lower than what was projected in the 2007 Load Forecast. Therefore, the 2008 Load Forecast Update starts from a lower point. F2009 sales to date are also lower than what was projected in the 2007 Load Forecast.

- Lower Economic Drivers. The economic drivers of the 2008 Load Forecast Update, including GDP, housing starts, retail sales and employment, are lower relative to the 2007 Load Forecast. This change is relatively consistent across the forecast horizon, and reflects a general forecast slowdown in economic activity over the next 24 months. This slowdown is due to a decline in the global and domestic demand for commodities and materials and the impacts of the financial and credit crisis. This downturn is not expected to be structural; that is, after the current slowdown, the rate of economic growth is expected to resume. Specific to BC Hydro's customer sectors, slower forecast growth in retail sales and employment drivers have led to reduced forecast sales in the commercial distribution and industrial distribution sectors. The residential sales forecast is lower, reflecting a reduction in forecast housing starts.

- Industrial Load. The industrial sector represents almost 40 per cent of BC Hydro's domestic electricity sales and is the most volatile year over year. The 2008 Load Forecast Update reflects updated industry sector information, revised production forecasts and revised expectations on future expansions in the main industrial sectors. The 2008 Load Forecast Update includes potential new mining load; however, the rate of development of these opportunities is highly dependent on future demand for the produced commodities. Incremental oil and gas loads are similarly included, particularly in the Dawson Creek and Fort Nelson regions of Northeast B.C. The former region is part of the BC Hydro Integrated System, while the latter region is discussed in section 2.8. The forestry sector represents 60 per cent of BC Hydro's industrial sector load. The 2008 Load Forecast Update reflects reduced forecast sales in the wood sector which is related to a declining United States (**U.S.**) housing market, declining newsprint sales, and lower pulp demand. The medium to long-term trends in forecast electricity sales to the forestry sector reflect diminished lumber and pulp production reflecting reduced fibre supply from the pine beetle infestation. In the 2007 Load Forecast, BC Hydro made a significant downwards revision to reflect the impacts of the mountain pine beetle in the interior forests. The 2008 Load Forecast Update does not introduce significant incremental changes with regards to this impact relative to what has been included in the 2007 Load Forecast.

- Impacts from Rate Increases. The 2008 Load Forecast Update incorporates proposed rate increases from BC Hydro's F2009/F2010 Revenue Requirements Application (**RRA**) for F2009 and F2010, and the August 2008 Long Term Rate Increase Forecast (**LTRIF**) set out in the attachment to the response to BCUC IR 1.7.1[7] for subsequent forecast years.

[7] The 2008 Load Forecast Update uses rate increases consistent with the F09/F10 RRA for the first two years and then uses an average increase in base rates for years 3 - 10. Years 11 - 20 are assumed to increase at a Consumer Price Index inflation rate of 2.1 per cent per annum. This approach results in the same cumulative rate increase after 10 and 20 years as submitted in the LTRIF attached to the response to BCUC IR 1.7.1 (Exhibit B-3).

The 2007 Load Forecast used an overall lower LTRIF generated in January 2008. The 2008 Load Forecast Update (before DSM) includes more rate increase-related savings than in the 2007 Load Forecast. The rate increase-related savings in the 2008 Load Forecast Update are now projected to be approximately 1,300 GWh/year for F2017, increasing to 1,600 GWh/year by F2027.

Table 2-2 2008 BC Hydro Sector and Integrated System Load Before DSM

Energy Load (GWh/year)	F2008	F2017	F2021	F2027	Change between F2008 – F2027	
					Total % Change	Average Annual Growth Rate (%)
Residential	17,462	19,998	21,233	23,246	33.1	1.5
Commercial	15,439	18,463	19,937	22,432	45.3	2.0
Industrial	18,737	20,678	20,224	20,363	8.7	0.4
Domestic Sales	53,002	60,763	62,976	67,812	27.9	1.3
Total Integrated including losses	58,735	66,172	68,480	73,847	25.7	1.2
Peak Demand (MW)	10,597	11,761	12,241	13,239	24.9	1.2

* Non-weather adjusted actual.

Tables 2-3 and 2-4, and Figures 2-1 and 2-2, show the difference between the 2007 Load Forecast filed in the 2008 LTAP and the 2008 Load Forecast Update for both energy and peak requirements. The 2008 peak forecast is lower than the 2007 peak forecast; however, the percentage change is not as great as between the 2007 and 2008 energy forecasts. The updated transmission peak forecast is below last year's transmission peak forecast for most of the forecast period, which is driven by lower industrial customer sales forecasts. The updated distribution peak forecast is close to the 2007 peak forecast, driven by lower estimates of residential account growth. BC Hydro is a winter peaking utility, and the overall system peak is highly sensitivity to colder temperatures. This is evidenced by high loads experienced during successive days in mid-December 2008, in which BC Hydro's Domestic System[8] peak demand reached approximately 10,000 MW.

This compares to the previous peak load set for the Domestic System of 10,113 MW on November 29, 2006.

Table 2-3 Forecast Energy Load Comparison - Before DSM Savings

Total Integrated Energy Load (GWh/year)	LTAP Application	Forecast Update	Change	% Change
F2008	58,366	58,735	369	0.6
F2017	68,289	66,172	-2,117	-3.1
F2021	71,079	68,480	-2,599	-3.7
F2027	76,778	73,847	-2,931	-3.8

* Non-weather adjusted actual.

Table 2-4 Forecast Peak Load Comparison Before DSM Savings

Total Integrated Peak Demand	LTAP Application	Forecast Update	Change	% Change
F2008	10,783	10,597	-186	-1.7
F2017	11,914	11,761	-152	-1.3
F2021	12,458	12,241	-218	-1.7
F2027	13,433	13,239	-194	-1.4

8 Domestic sales include sales to all BC Hydro residential, commercial and industrial customers and sales to the City of Westminster and FortisBC Inc. Integrated System Gross Requirements includes sales and system line losses for all BC Hydro customers connected to BC Hydro Integrated System and include firm export requirements to Seattle City Light and Hyder, Alaska (Tongass Power and Light Co. Inc.). Integrated Sales do not include sales and losses for Fort Nelson, and the Purchase Area and Zone II rate customers, which are defined at page 50 of Appendix D, Exhibit B-1-1.

Figure 2-1 Total Integrated Energy Requirements LTAP Application and Forecast Update

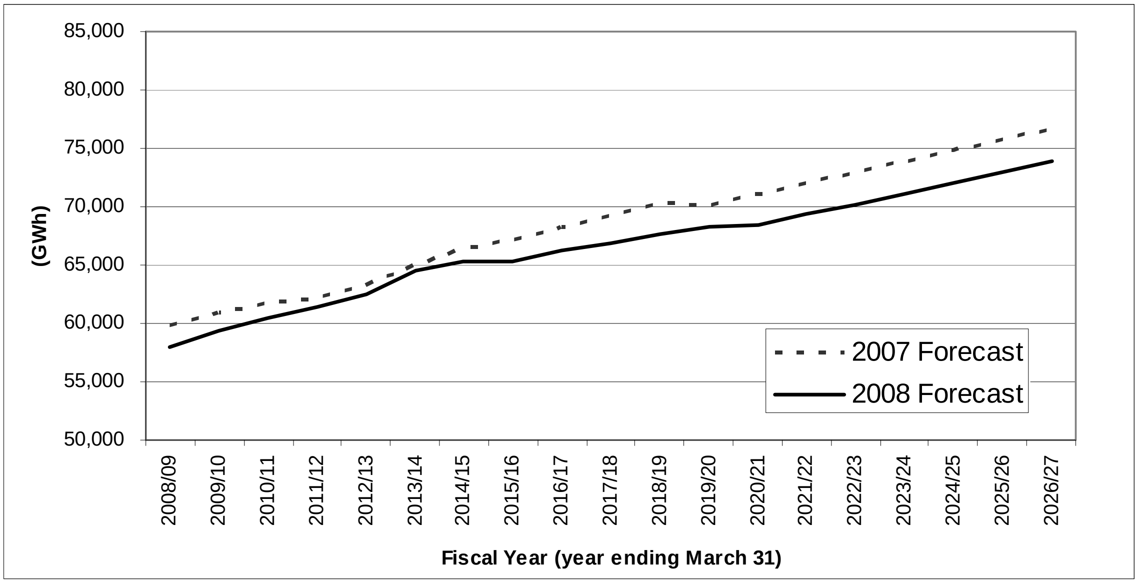
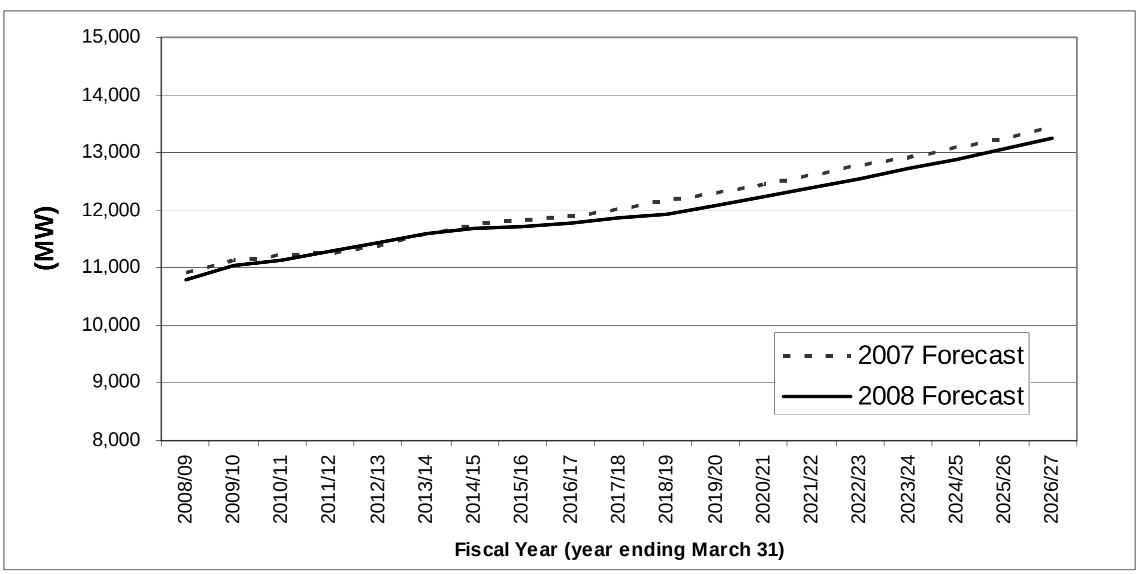


Figure 2-2 Total Integrated Peak Demand Requirements LTAP Application and Forecast Update



2.1.3 Electrification Scenarios

The 2008 Load Forecast Update incorporates relatively certain expected loads and future demand trends. As with the 2007 Load Forecast, the 2008 Load Forecast Update includes uncertainty bands around the mid load forecast estimated using a Monte Carlo model that examines the uncertainty in a set of key drivers including economic activity, weather, electricity rates and rate elasticities. These uncertainty bands represent a reasonable range around the mid 2008 load forecast to account for relatively predictable yearly perturbations in future loads around the mid forecast.

Nevertheless, to be prepared to meet future customer electricity requirements, BC Hydro is monitoring potential new loads that may result from future greenhouse gas (**GHG**)–related legislation, regulations and policy, new technologies and demographic trends. These prospective loads are not included in the mid 2008 load forecast, but have been considered as scenarios for study and potential inclusion in future load forecasts when these loads become more visible and quantifiable.

The broad themes of these load scenarios that could occur and have not been fully developed are as follows:

- Electrification driven by GHG-related legislation/regulations/policy and natural gas risk/price considerations; and

- Technological developments that result in significant changes in electricity use or use patterns.

Increasing prices, and price volatility of fossil fuels combined with the cost risk of future GHG emissions, may produce conditions that encourage electrification. Legislation, regulation and policies aimed at reducing GHG emissions may also promote electricity as a low-GHG-impact alternative to burning fossil fuels. The B.C. Climate Action Plan calls for electrification of truck stops and ports.[9] On August 6, 2008, the Climate Action Team (**CAT**) presented 31 recommendations for strategies and interim GHG targets for 2012 and 2016 in a report

[9] The B.C. Climate Action Plan is found at Attachment 1 to the revised response to BCUC IR 1.67.1 (Exhibit B-3-4).

entitled "Meeting British Columbia's Targets: A Report from the B.C. Climate Action Team".[10] CAT was established in November 2007 to help the B.C. Government reduce GHG emissions by 33 per cent in 2020. As part of the 31 recommendations to the B.C. Government, CAT considers electricity use as a key option for reducing GHG emissions and identifies the following new applications:

- Electric vehicles;
- Electrification of oil and gas facilities, thereby eliminating the need for natural gas-driven compressors, pumps and equipment; and
- Accelerate carbon capture and storage (**CCS**) deployment.

Currently BC Hydro has insufficient definitive information to develop credible electrification scenarios that could be incorporated into the 2008 mid load forecast. Instead, BC Hydro has estimated the total potential electricity consumption of end-uses that may see a shift to electricity in the future. These estimates were prepared to depict the range of possible future new loads. Below are the scenarios that BC Hydro has examined:

<u>Electric plug-in vehicles</u>

If all passenger vehicles currently in B.C. switched to electric plug-in vehicles (**EPV**), the impact on BC Hydro's load would be approximately 9,000 GWh[11] per year. BC Hydro should have several years of warning with respect to growing EPV load. Manufacturers would have to retool, and there would be North American orders and sales. BC Hydro is monitoring EPV production targets by manufacturers such as Nissan and General Motors. BC Hydro is participating in EPV research with Manitoba Hydro, Hydro Quebec and 34 other electric utilities in North America through the Electric Power Research Institute.

<u>Residential Space Heating and Water Heating</u>

The 2008 Load Forecast Update uses a projection of electricity use in residential building stock by application. In this forecast, approximately 20 per cent of the accounts use electric space heating as a primary source, and approximately 35 per cent use electric water heating,

[10] Attached to the response to IPPBC IR 2.6.1 (Exhibit B-4). The members of CAT are listed at page 44, and the mandate of CAT is set out at page 3, of the attachment.

[11] Assumptions used in calculation: 2.7 million licensed vehicles in B.C., average passenger vehicle use is 17,000 km/year, and EPVs use 0.2 kWh/km.

now and in the future. If all residential buildings in 2020 were to adopt electric space and water heating, there would be an additional 22,000 GWh and 4,000 GWh load,[12] respectively.

Oil and gas facilities

In the 2008 Load Forecast Update, BC Hydro includes oil and gas sector electrification load in its mid forecast. In addition, BC Hydro has developed scenarios around the mid forecast (high and low) that envision greater (and respectively lesser) degree of industry development and electrification than in the mid forecast. Specific to the Fort Nelson region, refer to section 2.8.1 for a discussion of the electrification scenarios for the oil and gas sector.

BC Hydro is investigating commercial and industrial end uses of electricity within the Northeastern B.C. oil and gas sector. The primary load impact would be the use of electric compression in the movement and processing of natural gas, versus the natural gas-fired compression traditionally used in this sector. An associated use of electricity would be in CCS of carbon dioxide (**CO_2**) discharge from natural gas processing facilities. These scenarios are currently in development, in consultation with the oil and gas industry.

2.2 Updated Attrition Information for F2006 Call

As shown in the Table 2-5, the attrition rate for the F2006 Call has increased since the 2008 LTAP Application was filed in June 2008.

Table 2-5 F2006 Call Attrition and Expected Energy

[Total Energy]	Awarded (GWh/year)	Terminated (GWh/year)	Forecast Attrition (GWh/year)	Terminated + Forecast Attrition (GWh/year)	Combined Attrition Factor (%)	F2006 Call Expected Energy (GWh/year)
2008 LTAP Application	7,093	1,677	1,630	3,307	47	3,786
2008 LTAP Evidentiary Update	7,093	1,919	2,848	4,767	67	2,326
Difference	0	242	1,218	1,460		-1,460

12 These high level estimates assume that 80 per cent of dwellings with non-electric space heating would have similar heating requirements to the existing 20 per cent of dwellings that currently use electric space heating. Similarly, the non-electric water heating dwellings are assumed to have similar water heating requirements to the existing 35 per cent of dwellings that currently use electric water heating.

As a result of the forecast reduction of 1,460 GWh/year in total expected energy supply from the F2006 Call, BC Hydro has removed 1,200 GWh/year (i.e., the firm portion) from its energy supply stack in the planning horizon. For the 2,326 GWh/year of expected energy from the F2006 Call, 1,910 GWh/year is firm energy that is included in the firm energy supply stack.

Different resource types have different attrition rates. In particular, coal-fired and biomass projects (comprising 3,219 GWh/year of total energy) from the F2006 Call have experienced significantly more attrition than other types of supply sources. The coal-fired and biomass projects from the F2006 Call have a very high attrition rate due to post-award Government and industry developments. As indicated in the 2008 LTAP, the two coal/biomass projects were removed from the supply stack due to the zero GHG requirement contained in Policy Action No. 20 of the 2007 Energy Plan. Furthermore, the other two biomass projects from the F2006 Call have been significantly impacted by the cost and availability of the biomass feedstock. The housing market in the U.S. continues to be depressed which has resulted in a number of recent shutdowns or significant curtailments of sawmill activities. Additionally, increased demand for wood pellets in other jurisdictions has tightened fibre availability and driven up wood residue costs beyond those traditionally experienced in the cyclical forest industry.

For the 3,874 GWh/year of other resources in the F2006 Call that are not coal or biomass projects, BC Hydro's current view is that there is an approximately 60 cent composite probability of such projects being completed, resulting in an attrition factor for such resources of approximately 40 per cent. In general, the higher than expected attrition rates for the F2006 Call have arisen due to:

- The recent volatility in the financial market has increased the cost of debt and equity for independent power producers (**IPPs**) and at the same time decreased the availability of credit and equity capital;
- The construction cost for power projects in B.C. has escalated at a rapid rate since 2006, exceeding the expectations of a number of F2006 Call proponents. While the economy and construction markets are expected to slow, potential cost savings to IPPs are reduced by the continued high prices for turbines and other key equipment based on a weak Canadian dollar and healthy demand for renewable energy projects around the world;

- Delays in receiving key permits and overall schedule delays have affected the ability of some projects to obtain production incentives from the Federal Government via the ecoENERGY for Renewable Power program.[13]

2.3 Updated Load/Resource Balance Prior to 2008 LTAP Actions

The impact of the changes as a result of the 2008 Load Forecast Update and F2006 Call attrition have offsetting impacts on the load/resource balance. For energy and capacity, the net change in requirements shows an increased need in the F2012 to F2015 period and decreased need thereafter as the decline in the load forecast becomes greater than the decline in IPP supply.

Tables 2-6 and 2-7 below provide a more detailed breakout of the changes to the energy and capacity load resource balances before the 2008 LTAP actions.

[13] The ecoENERGY for Renewable Power program pays 1 cent/kWh for up to 10 years, and applies to low-impact renewable electricity projects using technologies such as wind, hydro, biomass, geothermal, solar, wave and tidal. Eligible projects must be constructed by March 31, 2011.

Table 2-6 Energy Load/Resource Gap Before 2008 LTAP actions

(GWh/year)	F2012	F2013	F2014	F2015	F2016	F2017	F2018	F2019	F2020	F2021
LTAP Application[14]	-3,000	-3,900	-5,700	-7,100	-8,500	-11,500	-12,600	-14,200	-14,000	-15,000
Reduction in load forecast[15]	800	800	500	1,100	1,900	2,100	2,400	2,600	1,900	2,600
Reduction in IPP supply	-1,300[16]	-1,300	-1,200	-1,200	-1,200	-1,200	-1,200	-1,200	-1,200	-1,200
Net change in the Energy gap	-500	-500	-700	-100	700	900	1,100	1,400	700	1,400
(Increase or Decrease in Gap)	Increase	Increase	Increase	Increase	Decrease	Decrease	Decrease	Decrease	Decrease	Decrease
Evidentiary Update	-3,500	-4,400	-6,400	-7,200	-7,700	-10,600	-11,500	-12,800	-13,400	-13,600

(Values have been rounded to the nearest 100 GWh)

14 Consistent with Table 1-1 in Exhibit B-1.

15 Positive values are shown to signify that a reduction in the load forecast increases the load/resource gap.

16 Includes the impact of revised in-service dates for some pre-Commercial Operation Date projects.

Table 2-7 **Capacity Load/Resource Gap Before 2008 LTAP actions**

(MW)	F2012	F2013	F2014	F2015	F2016	F2017	F2018	F2019	F2020	F2021
LTAP Application[12]	-220	-300	-500	-640	-1,130	-1,240	-1,340	-1,530	-1,680	-1,830
Reduction in load forecast[17]	-20	-70	-10	50	120	150	160	230	220	220
Reduction in IPP supply	-130	-130	-130	-130	-130	-130	-130	-130	-130	-130
Change in Reserve Requirements[18]	20	20	20	20	20	20	20	20	20	20
Net change in the Capacity gap	-130	-180	-120	-60	10	40	50	120	110	110
(Increase or Decrease in Gap)	Increase	Increase	Increase	Increase	Decrease	Decrease	Decrease	Decrease	Decrease	Decrease
Evidentiary Update	-350	-480	-620	-700	-1,120	-1,190	-1,290	-1,420	-1,570	-1,720

(Values have been rounded to the nearest 10 MW)

17 Positive values are shown because a reduction in the load forecast increases the load/resource gap.

18 The drop in IPP supply increases the capacity gap; however, this is somewhat offset by an associated reduction in reserve requirements.

Figures 2-3 and 2-4 are new energy and capacity load/resource balances that incorporate the changes resulting from the 2008 Load Forecast Update and the update to the committed IPP supply net of attrition. For both energy and capacity, the gap between existing and committed supply and the demand forecast shows a need for additional resources as discussed in section 2.7.

Figure 2-3 Energy/Load Resource Balance

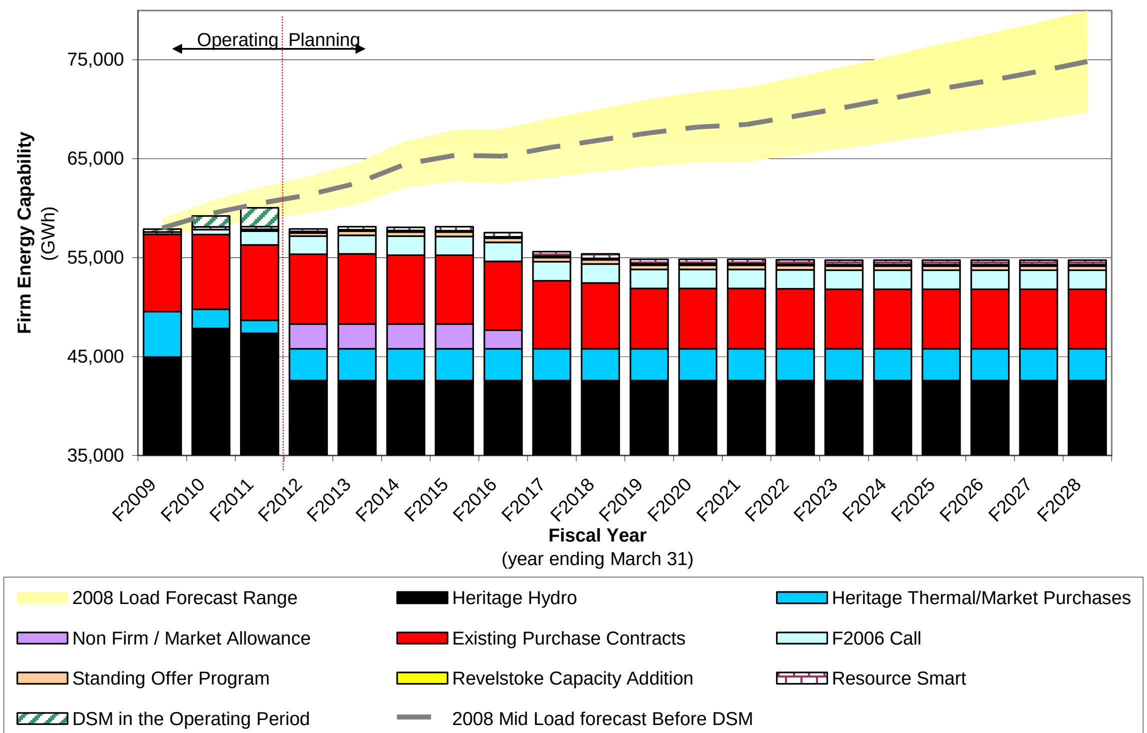
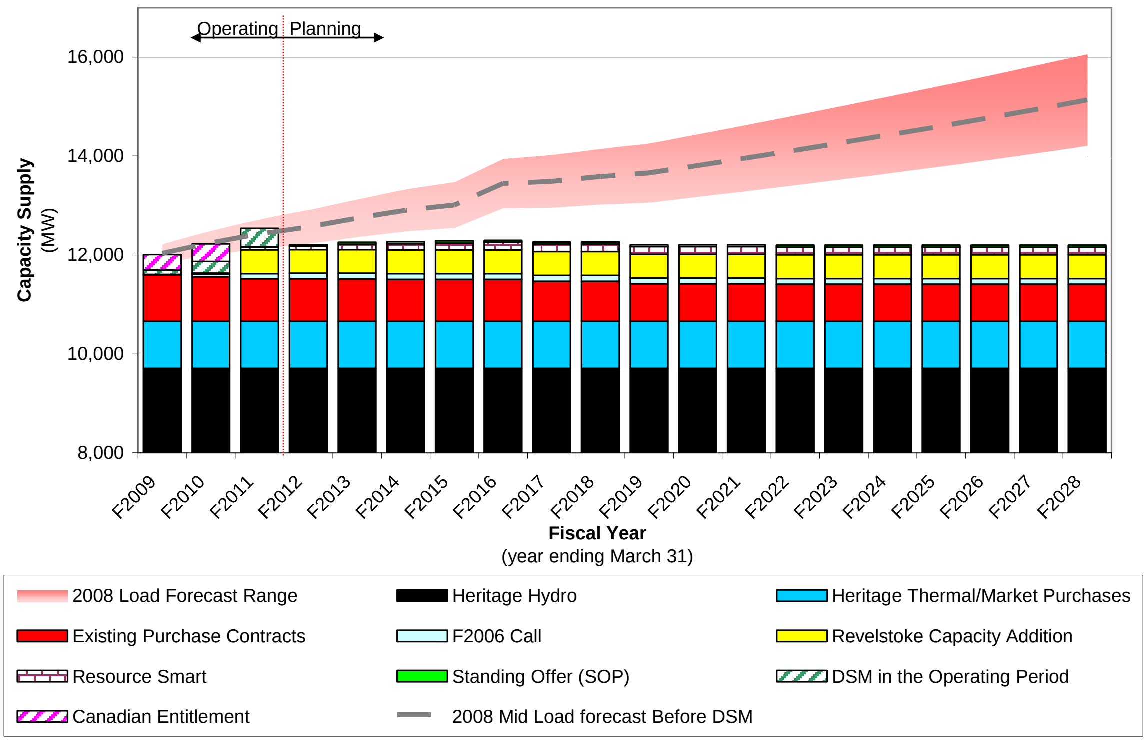


Figure 2-4 Capacity Load/Resource Balance



2.4 Impacts to the DSM Plan

This section is organized as follows:

- Section 2.4.1 discusses the impact of new information on the timing of changes to the Federal and B.C. Governments' proposed incandescent lighting regulations.
- Section 2.4.2 examines the impact of the 2008 Load Forecast Update on the economic conservation potential, which led BC Hydro to conclude that changes were warranted. The impact to BC Hydro's DSM Plan was analyzed first, before examining changes to the Clean Power Call target, because pursuant to subsections 44.1(2)(b) and (f) of the *Utilities Commission Act*[19] (***UCA***), BC Hydro must pursue all cost-effective DSM before relying on supply-side resources. BC Hydro reduced its expected savings from the DSM Plan by 1,300 GWh in F2020 (from 10,900 GWh to 9,600 GWh).

[19] R.S.B.C. 1996, c.473, as amended by the *Utilities Commission Amendment Act, 2008*, S.B.C. 2008, c.13, in force by Royal Assent on May 1, 2008.

- However, for the reasons set out in section 2.4.3, BC Hydro concluded that no change is warranted in its request that the BCUC determine that expenditures of $418.0 million for implementation of the DSM Plan in F2009, F2010 and F2011 are in the public interest under subsection 44.2(3)(a) of the *UCA*. In short, BC Hydro plans to pursue the same DSM initiatives but believes it is appropriate to reduce the level of expected savings for resource planning purposes.

2.4.1 Incandescent Lighting Regulation Developments[20]

Both the Federal and B.C. Governments propose to regulate the efficiency of incandescent lighting. These proposed regulations are the single largest source of codes and standards savings in the DSM Plan.[21] The timing of these regulations was uncertain in the summer of 2007 when the codes and standards savings were estimated for the DSM Plan. At that time, the Federal Government proposed an effective date of 2012 for the regulations but it was unclear whether resistance from lighting manufacturers would cause that date to shift outward. To be conservative, BC Hydro assumed that the savings would come online starting in F2016.

In 2008, the Federal Government enacted the federal regulations with effective dates in 2012, depending on lamp sizes.[22] Also, in 2008, the B.C. Government formally announced a regulation with effective dates in 2011 and 2012, again depending on lamp sizes.[23] Given this new information, BC Hydro is of the view that it is reasonable to expect the savings to come online three years sooner, starting in F2013. This change is estimated to deliver an

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20 The Federal Government has also changed the effective date of a regulation concerning ceiling fans relative to what was assumed in the DSM Plan. Unlike the lighting regulation, where the date has been advanced, the date for the ceiling fan regulation has been deferred. The ceiling fan regulation is not as significant as the lighting regulation. The estimated savings from the lighting regulation are 845 GWh/year in F2020, as compared to estimated savings of 123 GWh/year in F2020 from the ceiling fan regulation. The change in the effective date of the ceiling fan regulation decreases the level of expected savings in any one year over the next decade by up to 20 GWh/year, which is not considered to be material for resource planning purposes.

21 Exhibit B-1-1, Appendix K, to the 2008 LTAP, page 129.

22 Pursuant to amendments to the Energy Efficiency Regulations, SOR/94-651, enacted under Canada's *Energy Efficiency Act*, S.C. 1992, c.36.

23 The regulation is expected to be enacted under B.C.'s *Energy Efficiency Act*, R.S.B.C. 1996, c.114.

extra 480 GWh of energy savings in F2017. By F2021, the forecasts converge, and the difference resulting from this advancement is eliminated.

2.4.2 Economic Conservation Potential and Impact on Expected Savings

Reduction in Economic Conservation Potential

The reduction between the 2006 Load Forecast and 2008 Load Forecast Update impacts the amount of economic conservation potential in BC Hydro's service territory. In F2021, the 2008 Load Forecast Update for BC Hydro's Integrated System is 2,600 GWh lower than the 2007 Load Forecast and 5,500 GWh lower than the 2006 Load Forecast. The 2007 Conservation Potential Review (**CPR**)[24] filed as part of the 2008 LTAP used the 2006 Load Forecast in determining its reference case forecast of electricity use. Of the 5,500 GWh decrease in F2021, between the 2006 and 2008 load forecasts, an estimated 1,470 GWh is a result of the customer response to higher rate levels while the balance is a result of changes in the economic drivers and production forecasts underlying electricity load. The 2006 Load Forecast assumed that rates would increase at the rate of inflation whereas the 2008 Load Forecast Update assumed that rates would increase at a faster rate. Through the application of an assumed price elasticity of demand, the 2008 Load Forecast Update reflects the customer response to these higher rate levels.

BC Hydro assumes that 100 per cent of the rate level savings overlap with the economic conservation potential estimated in the 2007 CPR, because BC Hydro expects higher rate levels to spur customers to undertake lower cost electricity saving actions that would have been included within the economic conservation potential. BC Hydro further assumes that 30 per cent of the reduction in load due to changes in economic drivers and production forecasts overlaps with the economic conservation potential, on the grounds that only a portion of load represents "uneconomic" consumption that could be avoided through economic conservation. For example, a new standard-efficiency building may be expected to consume 100 units of electricity whereas the same building would consume 70 units of electricity if it incorporated all economic conservation opportunities. If that new building is eliminated from the load forecast due to the change in economic drivers, the forecast load

[24] Filed as Sub-Appendix L to the DSM Plan, which is Appendix K to the 2008 LTAP (Exhibit B-1-1).

drops by 100 units but economic conservation potential drops by only 30 units. The 30 per cent assumption used in BC Hydro's analysis is derived from the approximate ratio of economic conservation potential in the 2007 CPR to the forecast load before DSM. As a result, BC Hydro estimates that the economic conservation potential is 2,400 GWh/year[25] lower in F2021 relative to that estimated in the 2007 CPR (16,600 GWh/year as compared to 19, GWh/year).

Adjustment to Expected Savings

The above changes are sufficient in BC Hydro's view to warrant changes to the level of expected DSM savings for resource planning purposes in the 2008 LTAP from 10,900 to 9,600 GWh, by F2020.

Given the degree of analysis required, BC Hydro did not generate a new CPR or analyze the impacts of the above changes on an initiative-by-initiative basis. BC Hydro has commissioned CPRs only every five years or more due to their considerable cost and effort. To consider the impacts of the above load forecast changes on DSM deliverability risk, BC Hydro undertook a high level analysis and reviewed its level of reliance on DSM. There remains sufficient economic conservation potential to support the original DSM target of 10,900 GWh in F2020, but the level of risk associated with achieving this amount of DSM savings has increased due to the reduction in economic conservation potential. To adjust for this increased risk, BC Hydro will continue to implement the same DSM initiatives but will reduce its expectation of the savings that will result. Even with the same level of expenditures and a reduced level of expected savings, DSM remains cost-effective relative to new supply-side resources.

To adjust the level of expected savings that BC Hydro would rely upon, BC Hydro used the previous share of the economic conservation potential that was represented by the DSM Plan and reduced the expected level of savings from the DSM Plan to restore that same share given the reduction in the economic conservation potential. DSM Option A would have captured 54 per cent of the old economic conservation potential and would now capture

[25] 2,400 GWh/year = 1,470 GWh/year + 0.3(5,500 GWh/year - 1,470 GWh/year) less 10 per cent line losses since economic potential is estimated at the customer meter whereas load is estimated at an upstream point in the grid.

61 per cent of the new economic conservation potential. BC Hydro adjusted the level of expected DSM savings by 11 per cent such that the expected DSM savings continue to be 54 per cent of the new economic conservation potential. Refer to Table 2-8 below.

Table 2-8 DSM Share of Economic Conservation Potential

Initial DSM savings in F2020, at customer meter	**A**	**10,200 GWh/year**[26]
Adjusted DSM energy savings in F2020, at customer meter	**B**	**8,900 GWh/year**[27]
Old economic conservation potential in F2021	**C**	**19,000 GWh/year**[28]
New economic conservation potential in F2021	**D**	**16,600 GWh/year**
Initial DSM share of old economic conservation potential	**A/C**	**54%**
Initial DSM share of new economic conservation potential	**A/D**	**61%**
Adjusted DSM share of new economic conservation potential	**B/D**	**54%**

Degree of Reliance

BC Hydro also examined the degree of reliance on DSM. DSM represented 78 per cent of the F2020 14,000 GWh load/resource gap set out in Chapter 6 of the 2008 LTAP. Reducing expected DSM savings by 11 per cent from 10, GWh to 9,600 GWh would mean DSM represents approximately three quarters of the F2020 13,400 GWh load/resource gap, which represents a similar level of reliance on DSM as presented in the 2008 LTAP.

BC Hydro also examined the proportion of incremental load that would be met by DSM. DSM would have met 90 per cent of BC Hydro's incremental energy load between F2008

[26] Exhibit B-1--1, Appendix F14 to the 2008 LTAP, page 25, Table F14-4.

[27] This value is different than the 9,600 GWh noted above because it is a rate of savings at the customer meter whereas the 9,600 GWh is a volume of savings in the fiscal year grossed up to include line loss savings, which aligns with the presentation of energy in Chapter 6 of the LTAP.

and F2021 in the 2007 Load Forecast. DSM Option A would now meet 109 per cent of incremental energy load in the 2008 Load Forecast Update. Reducing expected DSM savings by 11 per cent would mean DSM meets 94 per cent of incremental energy load in the 2008 Load Forecast Update.

Table 2-9 shows the need for additional supply with and without the DSM savings discussed above. The bottom of Table 2-9 demonstrates the remaining gap that will need to be filled through acquisition processes.

Table 2-9 Energy Gap After DSM

	F2017 (GWh/year)	F2021 (GWh/year)	F2027 (GWh/year)
Gap Before 2008 LTAP actions	**-10,600**	**-13,600**	**-19,100**
Adjusted DSM	**7,600**	**9,900**	**11,600**
Energy Gap after Adjusted DSM	**-3,000**	**-3,700**	**-7,500**

2.4.3 DSM Plan Expenditure Determination Request

BC Hydro considered the developments described above and concluded that it will not propose any change to its request that the BCUC determine that expenditures of $418.0 million, required to implement BC Hydro's DSM Plan in F2009, F2010 and F2011, are in the public interest under subsection 44.2(3)(a) of the *UCA*, for the following reasons:

- Changed Circumstances. The reduction in the economic conservation potential could increase the difficulty, cost and risk of achieving a given level of energy savings. Some of the reduction in economic conservation potential is additional natural conservation which likely captures the lowest cost energy efficiency opportunities. BC Hydro anticipates it would have to spend more per unit to achieve incremental savings. BC Hydro is compensating for this by leaving the three-year DSM expenditure determination request

[28] Exhibit B-1-4, Sub-Appendix L of Appendix K to the 2008 LTAP, page 18, Exhibit 2.1.

as is, even though expected savings have decreased. Reducing the three-year expenditures would run the risk of actual savings being lower than the adjusted expected amount. Maintaining the level of expenditures preserves the prospect of achieving the adjusted expected savings and may result in BC Hydro achieving more savings than that amount, which would be a positive outcome. If BC Hydro had maintained the original level of planned DSM savings, it would likely have needed to increase the three-year expenditures to compensate for changed circumstances. BC Hydro does not want to increase the three-year expenditures because they represent a substantial departure from historical levels and BC Hydro wants to gain experience and learnings from three years of operation at this higher level of effort before contemplating further increases in expenditures;

- Uncertainty, risk, DSM flexibility and DSM cost recovery.
  - Uncertainty: BC Hydro faces uncertainty with respect to future load and DSM savings;
  - Risk: If BC Hydro reduces its DSM expenditure, it will be at increased risk of not meeting the self sufficiency requirement by 2016. The possibility that DSM savings would come in under the forecast level would be higher and, once such shortfall was recognized, there would likely not be time to recover through standard acquisition processes. This would likely result in BC Hydro relying on the Canadian Entitlement (**CE**) and other market contingency options, something that is contrary to Special Direction No. 10 to the BCUC;
  - Flexibility: BC Hydro can reduce the level of DSM expenditures in later years if it determines that additional savings are not needed. In that event, the net cost to ratepayers over the long term is limited because higher expenditures in early years are offset by lower expenditures in later years;
  - Asymmetric Flexibility: It is easier to ramp DSM down than up. Ramping DSM down involves cancelling DSM programs or restricting eligibility criteria, which BC Hydro can do on its own; whereas ramping DSM up requires trade ally cooperation and action, which can be difficult or slow to secure. If BC Hydro lowered the three-year DSM expenditure and savings are lower than expected, BC Hydro may not be able to

react in time to get DSM savings back on track in time to meet self-sufficiency in 2016; and

- DSM Cost Recovery: BC Hydro's rates are reset periodically, generally every two years, through RRAs based in part on forecast DSM expenditure. DSM expenditures are amortized over ten years, with 10 per cent flowed through to rates each year, starting in the year following the DSM expenditure. The risk of over-collection of DSM expenditures through rates, which would occur if actual DSM expenditures are less than forecast DSM expenditures, is limited to 10 per cent in year two, at which point rates are reset based on a new forecast of DSM expenditures which takes into account actual DSM expenditures; and

- Relative cost. The unit cost of DSM savings, assuming the original level of expenditures and the reduced level of expected savings is still lower cost than new supply.

  - The unit cost of original DSM program savings, assuming the original level of both expenditures and savings, was $56/MWh.[29] Under a worst-case scenario that assumes all of the decrease in DSM savings comes through programs, the unit cost of DSM program savings, assuming all of the planned expenditures are spent but only 78 per cent of the original savings are achieved,[30] would be $72/MWh, which is still well below IPP supply at $120/MWh.[31]

2.5 Bioenergy Call - Phase I RFP Results

On December 8, 2008, BC Hydro announced that it had selected four proposals for EPA awards in the Phase I RFP for a total of 579 GWh/year of firm energy and 65 MW of capacity. The awarded volume is lower than the target of 1,000 GWh/year, and the load/resource balance resulting from a successful implementation of the 2008 LTAP actions set out in section 2.7 has been adjusted accordingly. Given that three of the four Phase I

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[29] Exhibit B-4, response to JIESC IR 2.25.2. This is calculated by dividing the full DSM Plan costs, including portfolio-level costs, by program savings.

[30] Representing a 22 per cent reduction. Given program savings represent roughly 50 per cent of DSM Plan savings, a 22 per cent reduction in program savings would result in an 11 per cent reduction in DSM Plan savings.

[31] Exhibit B-3, response to BCUC IR 1.120.1, Table 5-15A, page 4 of 6.

RFP projects comprise generation from existing customer facilities,[32] there is little development risk and thus an attrition factor of 10 per cent is being used for the Phase I RFP energy. No change has been made to the expected contribution of Phase II of the Bioenergy Call.

BC Hydro is not seeking any BCUC endorsement or order with respect to the Phase I RFP. BC Hydro is filing the awarded EPAs with the BCUC pursuant to section 71 of the *UCA*.

2.6 Clean Power Call

The updated load/resource balance prior to the 2008 LTAP actions shows an energy shortfall of approximately 3,000 GWh in F2017 based on the 2008 mid load forecast and after reducing the expected savings from the DSM Plan. As previously indicated in Chapter 6 of the 2008 LTAP[33], there are no material self-build options which can meet the energy shortfall by 2016. Therefore, the projected energy shortfall will continue to be sourced from IPP purchases from BC Hydro's acquisition processes - specifically the Clean Power Call and the two phases of the Bioenergy Call.

2.6.1 New Clean Power Call Target

Given the reduced energy load/resource gap post-2015 arising from this Evidentiary Update, BC Hydro decided to reduce the target size of the Clean Power Call from 5,000 GWh/year to 3,000 GWh/year. Using a 30 per cent attrition factor, the post-attrition volume of the Clean Power Call for planning purposes is now 2,100 GWh/year of firm energy. Accordingly, BC Hydro is revising its Order sought as follows: BC Hydro requests that the BCUC endorse the proposed Clean Power Call pre-attrition target of 3,000 GWh/year. Refer to Attachment 1 to this Evidentiary Update, which sets out a new Appendix A to the 2008 LTAP, which is BC Hydro's revised Order sought.

[32] The three existing customer project proposals are: Canfor Pulp Ltd. Partnership's PGP Bio Energy Project in Prince George, Domtar Pulp and Paper Products' Kamloops Green Energy Project in Kamloops and Zellstoff Celgar Ltd. Partnership's Celgar Green Energy Project in Castelgar. The fourth proposal is an IPP project in Prince George owned by PG Waste to Energy Ltd.

[33] Page 6-28, lines 19-21, of Exhibit B-1.

BC Hydro issued a structured Clean Power Call RFP on June 11 2008. On November 25, 2008, BC Hydro received 68 proposals from 43 registered proponents in response to the Clean Power Call RFP. In aggregate the 68 proposals represent a total firm energy output of approximately 17,000 GWh/year, consisting of 45 hydro projects, 19 wind projects, two waste heat projects, one biogas project and one biomass project. Attachment 2 sets out the list of Clean Power Call proponents. BC Hydro is in the process of conducting an initial eligibility review.

BC Hydro is of the view that the reduced RFP target size can still accommodate IPPs proposing to develop larger projects. There are several hydro and wind projects bid into the RFP with project sizes above 100 MW. A few of these larger-sized projects can be selected along with some smaller projects to meet the 3,000 GWh/year target as long as they offer cost-effective energy.

2.6.2 Attrition Allowance for Clean Power Call

The Clean Power Call is targeted at resources that do not include coal-fired, natural gas-fired or forest-based biomass projects. As a group, the remaining resource types are similar to those that obtained EPAs through the F2006 Call, excluding the coal-fired and biomass projects in that Call. BC Hydro is of the view that an attrition allowance of 30 per cent for the Clean Power Call is appropriate for the following reasons:

- Excluding the coal-fired and biomass projects from the F2006 Call results in an expected attrition rate of about 40 per cent for the F2006 Call projects. BC Hydro is of the view that the market conditions were sufficiently unique and difficult during that period to expect that future acquisitions would be below that rate. Higher than normal attrition experienced by IPPs in B.C. is primarily attributed to the higher than expected rate of cost escalation. If the construction market stabilizes or softens in the near future, the likelihood and the extent of under-pricing should decrease thereby having a positive impact on project attrition rates.

- The most comprehensive study on attrition rates that BC Hydro is aware of is the California Energy Commission's (**CEC**) "Building a Margin of Safety Into Renewable Energy Procurements: A Review of Experience with Contract Failure". The CEC report supports the use of a 20-30 per cent attrition rate based on findings over a sample size of over 21,000 MW of renewable energy projects in North America and Europe.

- BC Hydro will continue to apply rigorous risk assessment processes in the Clean Power Call to avoid awarding contracts to high-risk projects.

2.7 Revised Base Resource Plan

The changes described in the prior sections of this Evidentiary Update demonstrate the degree to which BC Hydro continues to operate in an environment of significant uncertainty. These uncertainties include economic conditions, government legislative and policy initiatives, load forecasts, deliverability risks of both supply-side and demand-side resources, natural gas prices and future GHG offset costs. These uncertainties highlight the need for BC Hydro to have a BRP that has adequate supply in the short term and have CRPs that can be relied upon.

The revised BRPs are shown in Tables 2-10 and 2-11, and Figures 2-5 and 2-6.

Table 2-10 Base Resource Plan - Energy Table

← Operating | Planning →

(GWh)		F2009	F2010	F2011	F2012	F2013	F2014	F2015	F2016	F2017	F2018	F2019	F2020	F2021	F2022	F2023	F2024	F2025	F2026	F2027	F2028
Existing and Committed Supply																					
Heritage Hydroelectric		47,600	46,600	46,400	42,600	42,600	42,600	42,600	42,600	42,600	42,600	42,600	42,600	42,600	42,600	42,600	42,600	42,600	42,600	42,600	42,600
Heritage Thermal / Market Purchases		1,900	3,200	2,300	3,200	3,200	3,200	3,200	3,200	3,200	3,200	3,200	3,200	3,200	3,200	3,200	3,200	3,200	3,200	3,200	3,200
Resource Smart		200	300	300	300	300	300	400	400	500	500	500	500	500	500	500	500	500	500	500	500
Revelstoke Unit 5		0	0	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100
Existing Purchase Contracts (including Alcan 2008 EPA)		7,800	7,600	7,600	7,100	7,100	7,000	7,000	7,000	6,900	6,700	6,100	6,100	6,100	6,100	6,000	6,000	6,000	6,000	6,000	6,000
F2006 Call		0	500	1,400	1,800	1,900	1,900	1,900	1,900	1,900	1,900	1,900	1,900	1,900	1,900	1,900	1,900	1,900	1,900	1,900	1,900
Standing Offer Program		0	0	100	300	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400
Sub-total	(a)	57,600	58,100	58,100	55,400	55,600	55,600	55,600	55,700	55,600	55,400	54,800	54,800	54,800	54,800	54,700	54,700	54,700	54,700	54,700	54,700
Proposed New Supply																					
Bioenergy Call - Phase I		100	200	400	500	500	500	500	500	400	300	300	300	100	100	100	100	100	0	0	0
Bioenergy Call - Phase II		0	0	0	0	0	200	500	700	700	700	700	700	700	700	700	500	200	0	0	0
Clean Power Call		0	0	0	0	0	500	1,200	1,500	2,100	2,100	2,100	2,100	2,100	2,100	2,100	2,100	2,100	2,100	2,100	2,100
Mica Unit 5		0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	100	100	100	100
Future Resources		0	0	0	0	0	0	0	0	0	400	1,100	1,100	1,300	1,700	2,800	3,600	5,500	7,500	8,200	9,100
Sub-total	(b)	100	200	400	500	500	1,300	2,200	2,700	3,200	3,500	4,200	4,200	4,200	4,600	5,700	6,200	8,000	9,700	10,400	11,300
Additional Non-Firm Energy Supply																					
Non Firm / Market Allowance		0	0	0	2,500	2,500	2,500	2,500	1,900	0	0	0	0	0	0	0	0	0	0	0	0
Sub-total	(c)	0	0	0	2,500	2,500	2,500	2,500	1,900	0	0	0	0	0	0	0	0	0	0	0	0
Total Supply	**(d) = a + b + c**	57,700	58,300	58,600	58,400	58,600	59,300	60,300	60,300	58,800	58,900	59,000	59,000	59,000	59,400	60,400	60,900	62,700	64,500	65,200	66,100
Demand - Integrated System Total Gross Requirements																					
2008 High Load Forecast Before DSM	(e)	59,000	60,800	62,100	63,200	64,600	66,800	67,900	68,100	69,200	70,100	71,000	71,800	72,200	73,300	74,300	75,500	76,600	77,700	78,800	80,000
2008 Mid Load Forecast Before DSM	(f)	58,000	59,400	60,500	61,400	62,500	64,500	65,300	65,300	66,200	66,900	67,600	68,200	68,500	69,300	70,200	71,100	72,100	72,900	73,800	74,800
2008 Low Load Forecast Before DSM	(g)	57,000	58,100	58,900	59,500	60,400	62,100	62,700	62,500	63,200	63,700	64,200	64,600	64,700	65,400	66,000	66,800	67,500	68,200	68,900	69,700
Demand Side Management																					
Updated Option A - Mid Range with Loss Savings		300	1,100	1,900	3,000	3,700	4,700	5,600	6,700	7,600	8,300	9,100	9,600	9,900	10,200	10,400	10,800	11,100	11,500	11,600	11,900
	(h)	300	1,100	1,900	3,000	3,700	4,700	5,600	6,700	7,600	8,300	9,100	9,600	9,900	10,200	10,400	10,800	11,100	11,500	11,600	11,900
Load after DSM																					
2008 High Load Forecast after DSM	(e - h)	58,700	59,600	60,200	60,200	60,900	62,200	62,300	61,400	61,500	61,800	61,900	62,200	62,300	63,100	64,000	64,600	65,600	66,200	67,200	68,100
2008 Mid Load Forecast after DSM	(f - h)	57,700	58,300	58,600	58,400	58,800	59,800	59,700	58,600	58,500	58,600	58,600	58,700	58,600	59,200	59,800	60,300	61,000	61,400	62,200	62,900
2008 Low Load Forecast after DSM	(g - h)	56,700	57,000	56,900	56,500	56,700	57,400	57,100	55,800	55,500	55,400	55,200	55,100	54,800	55,200	55,700	55,900	56,400	56,700	57,300	57,800
Surplus / Deficit		**F2009**	**F2010**	**F2011**	**F2012**	**F2013**	**F2014**	**F2015**	**F2016**	**F2017**	**F2018**	**F2019**	**F2020**	**F2021**	**F2022**	**F2023**	**F2024**	**F2025**	**F2026**	**F2027**	**F2028**
2008 High Load Forecast Surplus / Deficit	**(d - e + h)**	0	0	0	-1,800	-2,200	-2,800	-2,000	-1,100	-2,700	-2,900	-2,900	-3,200	-3,300	-3,700	-3,500	-3,700	-2,800	-1,700	-2,000	-2,000
2008 Mid Load Forecast Surplus / Deficit	**(d - f + h)**	0	0	0	0	-200	-500	600	1,700	300	300	500	400	500	200	600	700	1,700	3,000	3,000	3,200
2008 Low Load Forecast Surplus / Deficit	**(d - g + h)**	0	0	0	1,900	1,900	1,900	3,200	4,400	3,300	3,400	3,800	3,900	4,200	4,200	4,800	5,000	6,300	7,800	7,900	8,300

Note: Values are rounded to the nearest 100 GWh

Table 2-11 Base Resource Plan - Capacity Table

Operating Planning

(MW)		F2009	F2010	F2011	F2012	F2013	F2014	F2015	F2016	F2017	F2018	F2019	F2020	F2021	F2022	F2023	F2024	F2025	F2026	F2027	F2028
Supply Requiring Reserves																					
Existing and Committed Supply																					
Heritage Hydroelectric		9,700	9,700	9,700	9,700	9,700	9,700	9,700	9,700	9,700	9,700	9,700	9,700	9,700	9,700	9,700	9,700	9,700	9,700	9,700	9,700
Heritage Thermal / Market Purchases		950	950	950	950	950	950	950	950	950	950	950	950	950	950	950	950	950	950	950	950
Resource Smart		0	0	50	50	100	150	150	150	150	150	150	150	150	150	150	150	150	150	150	150
Revelstoke Unit 5		0	0	500	500	500	500	500	500	500	500	500	500	500	500	500	500	500	500	500	500
Existing Purchase Contracts (excluding Alcan 2008 EPA)		650	650	650	650	650	650	650	650	650	650	600	600	600	600	600	600	600	600	600	600
F2006 Call		0	50	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100
Standing Offer Program		0	0	0	50	50	50	50	50	50	50	50	50	50	50	50	50	50	50	50	50
Sub-total	(a)	11,300	11,400	11,950	12,000	12,050	12,050	12,100	12,100	12,100	12,100	12,050	12,050	12,050	12,050	12,050	12,050	12,050	12,050	12,050	12,050
Proposed New Supply																					
Bioenergy Call - Phase I		0	0	50	50	50	50	50	50	50	50	50	50	0	0	0	0	0	0	0	0
Bioenergy Call - Phase II		0	0	0	0	0	50	50	100	100	100	100	100	100	100	100	50	50	0	0	0
Clean Power Call		0	0	0	0	0	50	100	100	150	150	150	150	150	150	150	150	150	150	150	150
Mica Unit 5		0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	450	450	450	450
Future Resources		0	0	0	0	0	0	0	0	0	50	50	50	100	100	100	150	250	350	350	450
Sub-total	(b)	0	0	50	50	50	100	200	250	300	300	350	350	350	350	350	350	900	1,000	1,000	1,050
Supply Requiring Reserves	**(c) = a + b**	11,300	11,400	12,000	12,050	12,100	12,200	12,300	12,350	12,400	12,400	12,400	12,400	12,400	12,400	12,400	12,400	12,950	13,050	13,050	13,100
Reserves (see footnote)																					
14% of Supply Requiring Reserves	**(d) = 14% * c**	1,600	1,600	1,700	1,700	1,700	1,700	1,700	1,750	1,750	1,750	1,750	1,750	1,750	1,750	1,750	1,750	1,800	1,800	1,800	1,850
Minus: 400 MW market reliance	**(e)**	-400	-400	-400	-400	-400	-400	-400	0	0	0	0	0	0	0	0	0	0	0	0	0
Net Reserves	**(f) = d + e**	1,200	1,200	1,300	1,300	1,300	1,300	1,300	1,750	1,750	1,750	1,750	1,750	1,750	1,750	1,750	1,750	1,800	1,800	1,800	1,850
Supply Not Requiring Reserves																					
Existing and Committed Supply																					
Alcan 2008 EPA		300	250	200	200	200	200	200	200	150	150	150	150	150	150	150	150	150	150	150	150
Sub-total	(g)	300	250	200	200	200	200	200	200	150	150	150	150	150	150	150	150	150	150	150	150
Supply Not Requiring Reserves	**(g)**	300	250	200	200	200	200	200	200	150	150	150	150	150	150	150	150	150	150	150	150
Effective Load Carrying Capability																					
Supply Requiring Reserves - Reserves + Supply Not Requiring Reserves	**(h) = c - f + g**	10,400	10,450	10,950	11,000	11,000	11,100	11,150	10,800	10,800	10,850	10,800	10,800	10,800	10,800	10,850	10,850	11,300	11,350	11,350	11,450
Demand - Integrated System Total Gross Requirements																					
2008 High Load Forecast Before DSM	**(i)**	11,000	11,300	11,450	11,600	11,850	12,000	12,150	12,200	12,300	12,400	12,550	12,700	12,900	13,100	13,300	13,500	13,700	13,900	14,150	14,350
2008 Mid Load Forecast Before DSM	**(j)**	10,800	11,050	11,150	11,300	11,450	11,600	11,700	11,700	11,750	11,850	11,950	12,100	12,250	12,400	12,550	12,700	12,900	13,050	13,250	13,400
2008 Low Load Forecast Before DSM	**(k)**	10,600	10,800	10,850	10,950	11,050	11,150	11,250	11,200	11,250	11,300	11,350	11,450	11,550	11,700	11,800	11,950	12,050	12,200	12,350	12,500
Demand Side Management																					
Updated Option A - Mid Range with Loss Savings		100	250	350	550	650	800	950	1,150	1,300	1,450	1,600	1,700	1,750	1,800	1,850	1,950	2,000	2,100	2,100	2,200
Sub-total	**(l)**	100	250	350	550	650	800	950	1,150	1,300	1,450	1,600	1,700	1,750	1,800	1,850	1,950	2,000	2,100	2,100	2,200
Load after DSM																					
2008 High Load Forecast after DSM	**(i - l)**	10,900	11,050	11,100	11,100	11,150	11,200	11,200	11,050	10,950	10,950	10,950	11,050	11,150	11,300	11,450	11,550	11,700	11,850	12,000	12,150
2008 Mid Load Forecast after DSM	**(j - l)**	10,700	10,800	10,800	10,750	10,800	10,800	10,700	10,550	10,450	10,400	10,350	10,400	10,500	10,600	10,700	10,800	10,900	11,000	11,100	11,250
2008 Low Load Forecast after DSM	**(k - l)**	10,500	10,550	10,500	10,400	10,400	10,350	10,250	10,050	9,900	9,850	9,750	9,800	9,800	9,900	9,950	10,000	10,050	10,150	10,250	10,300
Effective Load Carrying Capability Surplus / Deficit		**F2009**	**F2010**	**F2011**	**F2012**	**F2013**	**F2014**	**F2015**	**F2016**	**F2017**	**F2018**	**F2019**	**F2020**	**F2021**	**F2022**	**F2023**	**F2024**	**F2025**	**F2026**	**F2027**	**F2028**
2008 High Load Forecast Surplus / Deficit	**(h - i + l)**	**-450**	**-600**	**-150**	**-100**	**-150**	**-100**	**0**	**-250**	**-150**	**-150**	**-150**	**-250**	**-350**	**-500**	**-600**	**-750**	**-400**	**-450**	**-650**	**-750**
2008 Mid Load Forecast Surplus / Deficit	**m = (h - j + l)**	**-300**	**-350**	**150**	**250**	**250**	**300**	**450**	**250**	**350**	**400**	**450**	**400**	**350**	**200**	**150**	**50**	**400**	**400**	**250**	**200**
2008 Low Load Forecast Surplus / Deficit	**(h - k + l)**	**-100**	**-100**	**450**	**550**	**600**	**750**	**900**	**750**	**900**	**1,000**	**1,050**	**1,050**	**1,000**	**950**	**850**	**850**	**1,250**	**1,250**	**1,150**	**1,100**
Additional Supply Potential																					
Canadian Entitlement	**(n)**	300	350	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Surplus / Deficit with Canadian Entitlement	**(m + n)**	**0**	**0**	**150**	**250**	**250**	**300**	**450**	**250**	**350**	**400**	**450**	**400**	**350**	**200**	**150**	**50**	**400**	**400**	**250**	**200**

Reserve Footnote

BC Hydro's reserves are based on 14% of total supply excluding the 400 MW market reliance prior to F2016 and the Alcan 2008 EPA.

Note: values are rounded to the nearest 50 MW.

Figure 2-5 Base Resource Plan - Energy Graph

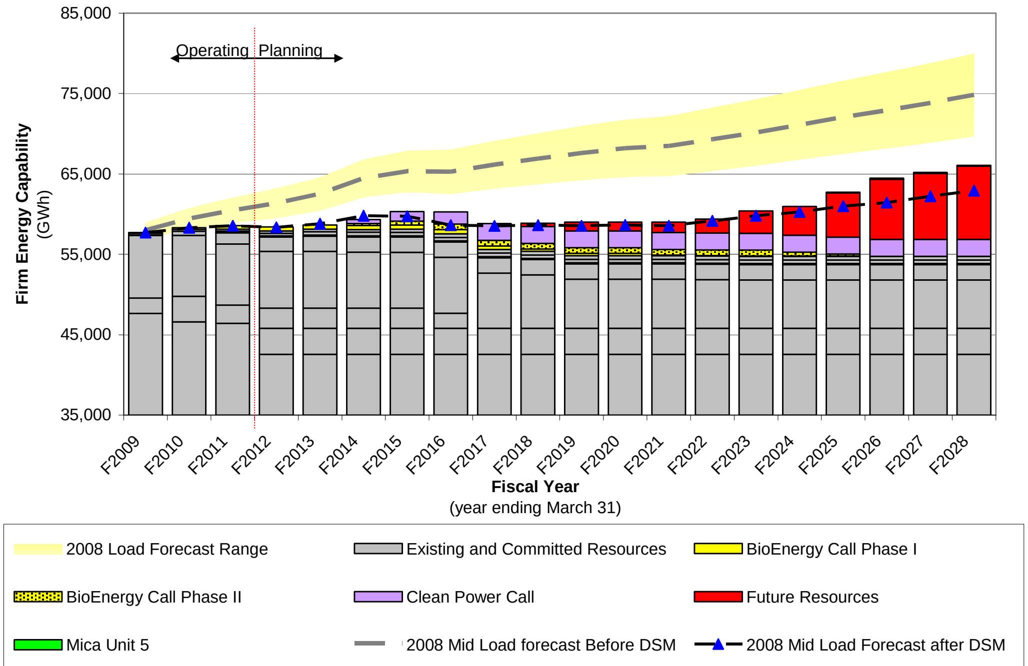
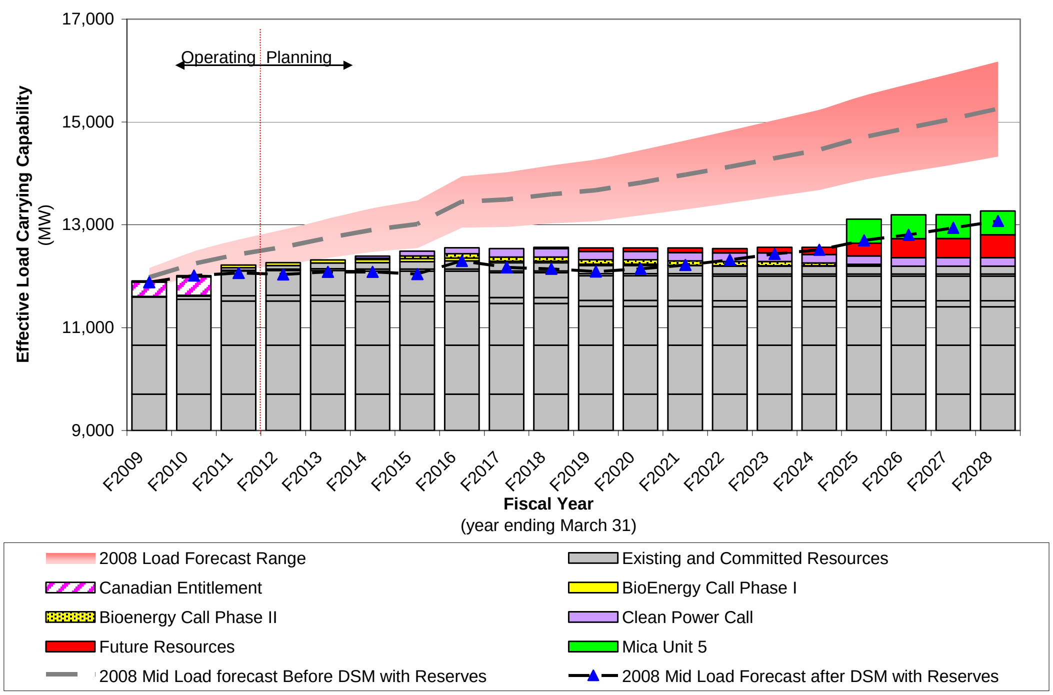


Figure 2-6 Base Resource Plan - Capacity Graph



The impact of the changed load forecast, F2006 Call attrition and revised 2008 LTAP actions are as follows:

- The reduced load forecast lessened the requirement for additional resources post-2015;
- The increased attrition from the F2006 Call reduces supply in the critical F2012 to F2014 timeframe;
- The reduced savings forecast from DSM Option A, given the expected load reductions and maintaining a degree of deliverability risk consistent with the initial 2008 LTAP Application, reduces DSM savings proportionately across the planning horizon;
- To achieve the self-sufficiency requirement and to reflect the reduced need in F2017, BC Hydro has reduced the planned Clean Power Call firm energy volumes to 2,100 GWh/year. With an attrition allowance of 30 per cent, this will result in a 3,000 GWh/year Clean Power Call target;
- The overall impact of the changes in this Evidentiary Update is most significant in the F2012 to F2014 timeframe. The combined impact of input assumption changes and

resulting 2008 LTAP actions results in a small deficit in firm energy supply in F2013 and F2014;

- The expected timing of the Clean Power Call resources in-service dates (**ISDs**) does not align well with the F2013/F2014 shortfalls as delivery is expected to begin in F2014 with the substantial deliveries to begin in the F2015 to F2017 timeframe;

- The capacity reduction does not have a significant impact on available capacity until late in the planning period. This reduction drives the need for a Mica Unit in F2025 in the BRP.

2.7.1 Short Term Deficit

To manage the net short term energy deficit of 200 GWh/year and 500/GWh/year in F2013 and F2014 respectively, BC Hydro plans to undertake the following actions:

1. Where appropriate, enter into discussions with IPPs that have bid into the Clean Power Call to assess the potential for these projects to advance their ISDs to the F2012 to F2014 time frame. The inclusion of a negotiations phase into the Clean Power Call RFP facilitates entering into any such discussions.

2. Depending upon the outcome of the IPP discussions, BC Hydro would undertake to advance its DSM plans sufficiently to manage the short term deficit. BC Hydro has not had adequate time to assess the viability of advancing savings and the impacts upon DSM expenditures and as a result is not changing its DSM expenditure determination request. However, notionally, BC Hydro would look to advance savings in programs that are amenable to such adjustments.

3. Evaluate any other power acquisition opportunities that may present themselves over the course of the next several years as alternatives to secure short term supplies.

Given the relatively short lead time to the F2013/F2014 time frame, meeting these energy shortfalls may necessitate reliance on contingency plans. Ultimately, if the energy shortfall persists, BC Hydro would rely upon the markets for electricity supply, including potentially relying on the CE.

2.7.2 Longer Term Deficits

In the longer term period of F2018 to F2028, BC Hydro currently forecasts that it will need to secure additional supplies. BC Hydro has not and does not yet need to determine what those resources will be. Options include undertaking additional DSM, conducting additional call processes or potentially developing Site C if the B.C. Government determines that it is a resource BC Hydro can pursue.

2.7.3 Contingency Resource Plans

The timing of Mica Units 5 and 6 in both CRP#1 and CRP#2, and the potential timing for Site C in CRP#2, are unchanged as a result of the updated inputs and 2008 LTAP actions as shown in this Evidentiary Update. The capacity demand change was largely offset by reduced IPP capacity contribution and the methods for assessing the capacity-related uncertainty as shown in the CRPs has not been altered.

Table 2-12 shows the revised CRP shortfall risks originally shown in Table 6-17 of Exhibit B-1 as updated in Revision 3 dated September 5, 2008.[34]

[34] Exhibit B-1-8.

Table 2-12 CRP Shortfall Risks

Risk	Rationale	Capacity Reduction for CRP Purposes (MW)		Energy Shortfall Risk (GWh)	
		F2017	F2028	F2017	F2028
Load Forecast Uncertainty	Peak load and energy requirements can increase as a result of either sustained growth or low temperatures on winter peak.	530	930	3,000	5,200
DSM Deliverability Risk[35]	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 Tables 6-2 and 6-3 of Exhibit B-1.	270	450	1,400	2,500
Burrard Unit Catastrophic Failure	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.	150	150	n/a	n/a
Calls Capacity Reduction	Based upon less Bioenergy projects being successful.	50	n/a	400	n/a
Total Reduction:		**1,000**	**1,530**	**4,800**	**7,700**

Tables 2-13 and 2-14 show the timing of Mica Units 5 and 6, and Site C, in CRP#1 and CRP#2 originally shown in Tables 6-20 and 6-22 of Exhibit B-1.

Table 2-13 CRP#1

Unit	BRP	CRP#1
Mica 5	F2025	F2014
Mica 6	Not Required	F2016

35 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. The reduction is 144 MW in F2020.

Table 2-14 CRP#2

Unit	BRP	CRP#2
Site C	n/a	F2019
Mica 5	F2025	F2014
Mica 6	Not Required	F2016

The updated CRP load/resource tables and graphs that reflect the updated information are provided in Attachment 6.

2.8 Fort Nelson Service Area

2.8.1 2008 Load Forecast Update

BC Hydro has completed its 2008 Load Forecast Update. The 2008 Load Forecast Update, included in section 2.1, includes an updated forecast for the Fort Nelson region.

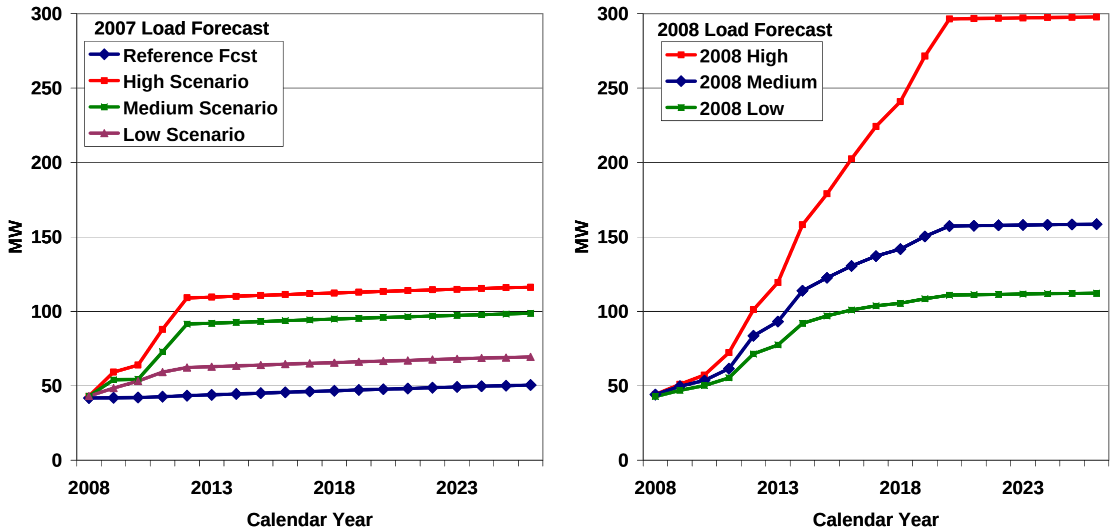
Events that have occurred during 2008 have led BC Hydro to conclude that there will be a significant increase in the expected load for the region. As was described in the original filing and in the August 25, 2008 (Exhibit B-1-7) and October 24, 2008 (Exhibit B-1-10) evidentiary updates, increased oil and gas activity in the Horn River basin is putting upward pressure on future expected loads in the region. Recent developments include:

- BC Hydro has received a draft interconnection request for service to the Horn River Basin for 20 to 40 MW with an ultimate load of 100 to 120 MW;

- On behalf of local member producers, CAPP provided BC Hydro with the CAPP Forecast, which is a forecast of gas production and the associated expectation for electricity demand for the Horn River Basin region. A copy of the CAPP Forecast is attached as Attachment 3 to this Evidentiary Update.

As a result of the above, and combined with BC Hydro's load forecast analysis, BC Hydro has significantly increased its 2008 Load Forecast for the region. Figure 2-7 presents the 2007 Reference Forecast and scenarios at the left and the new 2008 high, mid and low forecasts at the right.

Figure 2-7 Comparison of the 2007 Load Forecast to the 2008 Load Forecast



The new 2008 low forecast is now similar to the 2007 high scenario, with the new 2008 high forecast being more than six times BC Hydro's current load in the region. The above-mentioned draft interconnection request represents a load, on its own, that is similar to BC Hydro's total 2008 low forecast for the whole Fort Nelson region including the Horn River Basin.

Load uncertainty that could cause the load to be outside the bounds of the 2008 high and low forecasts are as follows:

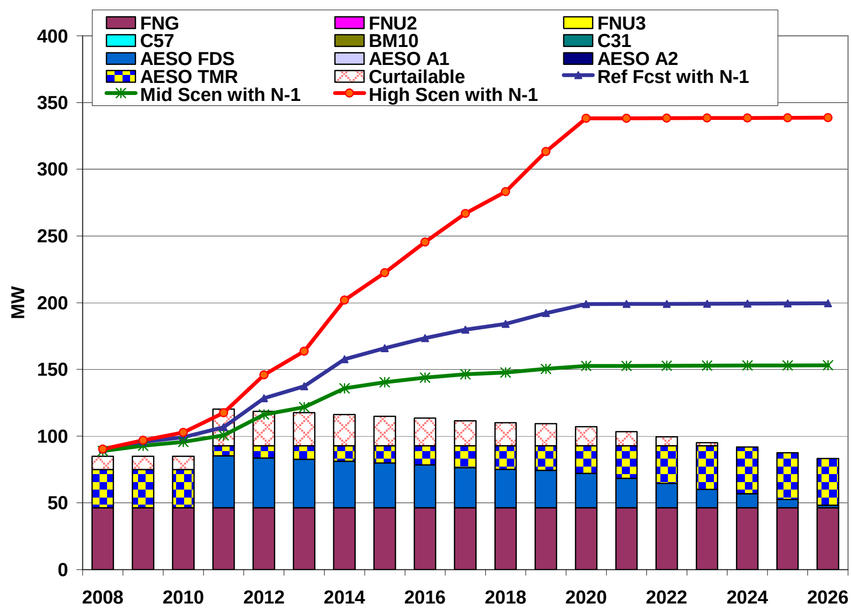
- Potential above the 2008 high forecast. There is still some potential for loads to be significantly above the 2008 high forecast. If the full CAPP Forecast were to occur, the load in the region would be approximately 200 MW above BC Hydro's 2008 high forecast. Even at that level, the CAPP Forecast does not include any load for electrification of distributed loads at well sites. If natural gas producers decided to fully electrify their operations, the loads could be higher than that identified in the CAPP Forecast, all else being equal.

- Potential below the low forecast: The natural gas industry proponents may install cogeneration to meet the load if BC Hydro is not able to provide service as may be requested or if there are business reasons for the proponents to self-supply. This could reduce the load that would ultimately be supplied by BC Hydro.

2.8.2 Update to the Load/Resource Balance before implementing the Fort Nelson LTAP Base Plan (FN LTAP Base Plan)

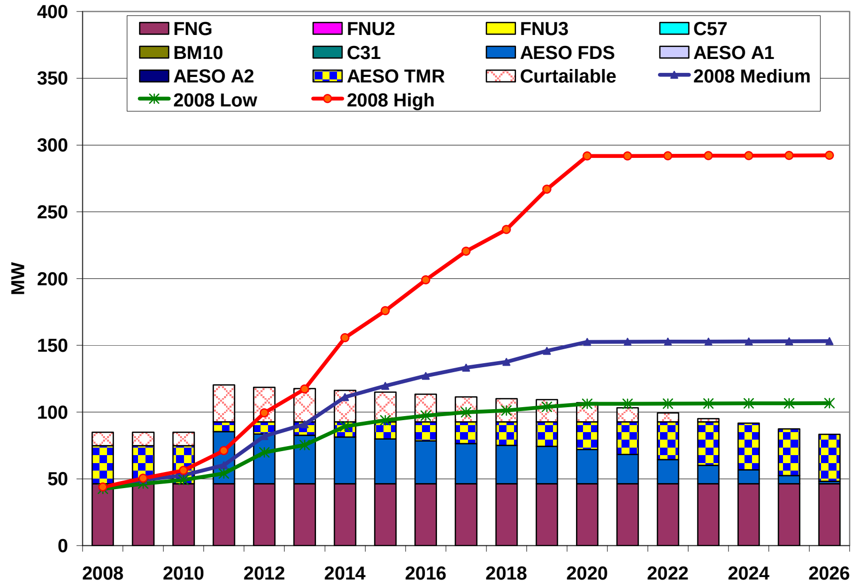
The Peak Load/Resource Balance, including reserves and before implementing the FN LTAP Base Plan, but including DSM in Fort Nelson associated with BC Hydro's DSM Plan and including all capacity that may be available from the Alberta Electric System Operator (**AESO**), is provided in Figure 2-8. As shown: (1) there is no year under any of the three load forecasts that BC Hydro can meet all forecast load on a firm basis; and (2) the mid forecast can only be met in 2011.

Figure 2-8 Current and Committed Load/Resource Balance including Reserves



Excluding reserves, the load/resource balance is as presented in Figure 2-9.

Figure 2-9 Current and Committed Load/Resource Balance before reserves



2.8.3 Update to the FN LTAP Base Plan

The FN LTAP Base Plan includes commitment of Fort Nelson Generating Station Upgrade Project Case 3 (**FNGU 3**) and the AESO A1 transmission upgrade. With these resources in service, there is a reduced requirement to rely on some curtailable load; however, BC Hydro is capable of meeting the mid load forecast through 2013 and the low forecast through 2014.

Figure 2-10 Base Portfolio including Reserve Requirements

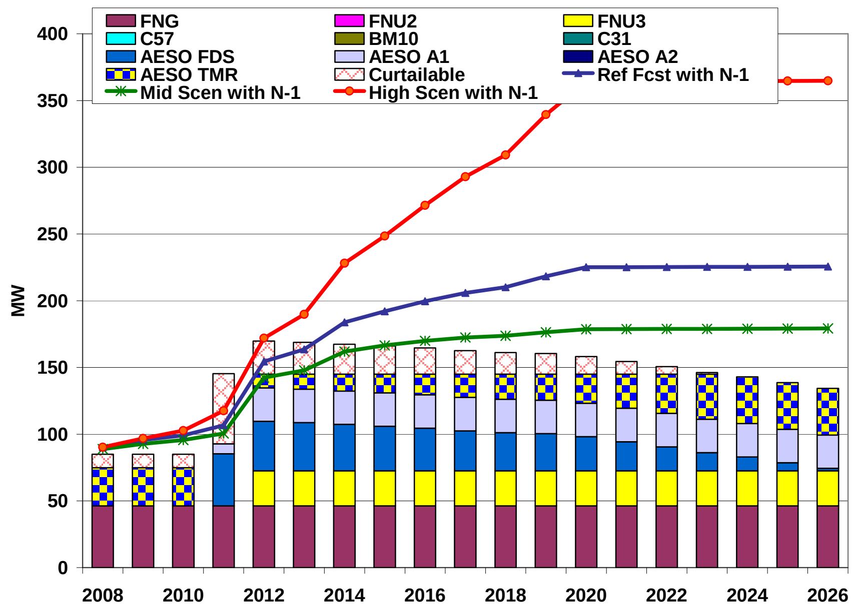
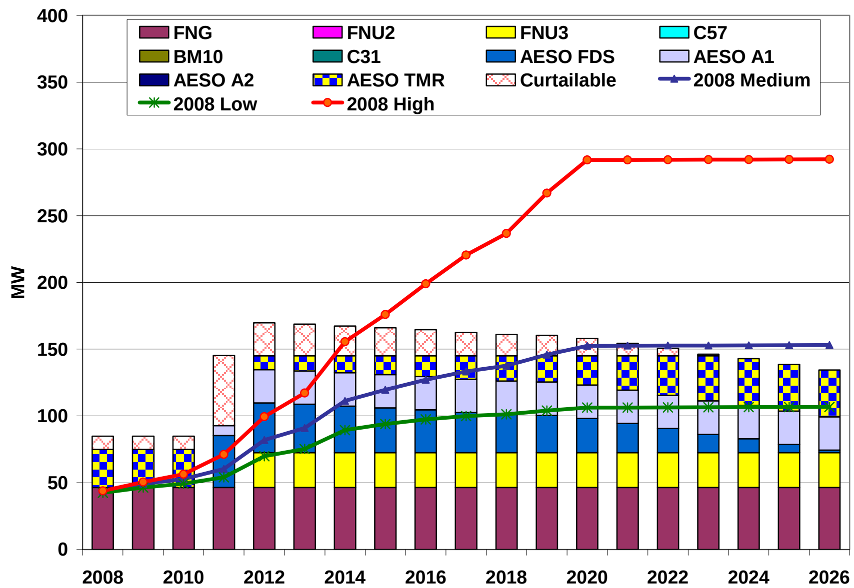


Figure 2-11 Base Portfolio before Reserve Requirements



2.8.4 Contingency Plans to meet Possible Load Growth

BC Hydro continues to advance the state of readiness of potential resource options to meet load growth above that which can be met with the FN LTAP Base Plan.

The current status of planning activities is as follows:

1. BC Hydro and industry representatives are forming a Fort Nelson region load forecast working group. BC Hydro will chair the group with a first meeting to be held in January 2009;

2. British Columbia Transmission Corporation (**BCTC**) transmission studies:

   a) Preparatory work for a BCTC tariff-based interconnection study in response to the draft interconnection request is being established; pursuant to the tariff, the study would commence once a final interconnection request is received; and

   b) A non-tariff study for BC Hydro on the alternative transmission options to interconnect loads of 250 to 800 MW in the Fort Nelson region to the B.C. interconnected system is currently underway, and expected to be completed in the second quarter of 2009;

3. BC Hydro continues to work with the AESO on possible interconnection solutions, particularly for the short to mid term, and in conjunction with the BCTC studies;

4. BC Hydro has initiated an Investigation phase study to install a second combined cycle gas turbine at Fort Nelson Generating Station. The study is expected to be completed by the second quarter of 2009; and

5. BC Hydro is exploring the possibility of generation and cogeneration (self generation) with industry groups in the region.

None of these resource options are yet at a stage where any commitment to an Implementation phase of development is required, however, the results of this work is expected to provide BC Hydro with the basis to be able to make further commitments in the second half of 2009, subject to further load certainty.

3 DSM Regulation

BC Hydro's originally requested that the BCUC, as part of determining that the 2008 LTAP is in the public interest under subsection 44.1(6)(a) of the *UCA*, endorse:

> "the residential Low Income DSM program, which has a Non-Participant Test [referred to as the **Ratepayers Impact Measure** or

> **RIM Test**] benefit-cost ratio of 0.6 and a [TRC] … benefit-cost ratio of 0.9”.[36]

BC Hydro requested BCUC endorsement of the residential Low Income DSM Program to comply with Directive 60 of the BCUC’s decision with respect to BC Hydro’s F05/F06 RRA.[37] Directive 60 of the F05/F06 RRA Decision provides:

> “The Commission Panel … directs BC Hydro to seek approval for and file tariffs for all new Power Smart programs with a RIM benefit/cost ratio of less than 0.8 and/or a TRC benefit/cost ratio of less than 1.0. For those Power Smart programs with a RIM benefit to cost ratio of less than 0.8, BC Hydro is directed to justify with each REAP filing the continuation of those programs”.

The DSM Regulation impacts Directive 60, as discussed below.

As set out in Table 1-2 of the 2008 LTAP, the 2007 Energy Plan establishes a 50 per cent conservation target for BC Hydro (Policy Action 1) and encourages utilities to pursue cost-effective and competitive DSM opportunities (Policy Action 3). The B.C. Government amended the *UCA* to facilitate the achievement of these and other policy actions in the 2007 Energy Plan. For example, section 44.1(8)(c) of the *UCA* directs the BCUC to consider the adequacy and cost-effectiveness of demand-side measures when determining whether or not to accept a utility’s long term resource plan. Section 125.1(4)(e) of the *UCA* gives the Minister of Energy, Mines and Petroleum Resources (**Minister**) the power to make regulations with respect to the adequacy and cost-effectiveness of demand-side measures. The Minister issued the DSM Regulation under Section 125.1(4)(e) of the *UCA* on 7 November 2008.

The following is a brief description of the provisions of the DSM Regulation that are relevant to Directive 60 of the F05/F06 RRA Decision and the residential Low Income DSM program:

- *Application* – Section 2 of the DSM Regulation provides that the DSM Regulation only applies to BC Hydro at present;

[36] Exhibit B-1, page 1-3, lines 1--4.

[37] *In the Matter of British Columbia Hydro and Power Authority’s 2004/05 to 2005/06 Revenue Requirements Application*, Reasons for Decision, October 29, 2004, page 224 (referred to as the **F05/F06 RRA Decision**).

- *Adequacy* – Subsection 3(a) stipulates that to be considered adequate for purposes of subsection 44.1(8)(c) of the *UCA*, BC Hydro's DSM Plan must include a low income program; and

- *Cost-effectiveness* – Subsection 4(2)(b) of the DSM Regulation directs the BCUC to grant a 30 per cent adder to the benefits of low income programs in the TRC test. Subsection 4(6) of the DSM Regulation prevents the BCUC from using the RIM test to determine that DSM is not cost-effective.

As a result of subsections 4(2)(b) and 4(6) of the DSM Regulation, BC Hydro is no longer requesting BCUC endorsement of the residential Low Income DSM program as part of the 2008 LTAP. The request for endorsement stemmed from the residential Low Income DSM program falling below both the TRC and RIM benefit/cost ratio thresholds established by the BCUC in the F05/F06 RRA Decision. The 30 per cent TRC adder increases the program's TRC benefit/cost ratio from 0.9 to 1.2, so it no longer falls below the TRC threshold of 1.0 in Directive 60. In addition, in BC Hydro's view subsection 4(6) of the DSM Regulation eliminates that part of Directive 60 requiring BC Hydro to seek approval for new DSM programs with a RIM benefit/cost ratio of less than 0.8.

4 Proposed Capital Plan Review Process

4.1 Background

One issue addressed in BC Hydro's F07/F08 RRA Negotiated Settlement Agreement[38] (**NSA**) was the manner in which the BCUC would review BC Hydro's capital plans. Sections 19 and 20 of the NSA set out the parameters for BC Hydro's capital plan filing and its major threshold project applications respectively:

> 19. BC Hydro will file its Capital Plan bi-annually. The Capital Plan will identify all capital expenditures and for the purposes of this provision the term "capital expenditures" will include those demand-side management expenditures that are amortized, in the then-current fiscal period and the following fiscal period, as well as total expenditure and in-service date forecasts for projects underway in those periods. In addition, the Capital Plans will specifically identify projects with gross project costs greater than $2 million on an aggregated basis. These bi-annual filings will satisfy BC Hydro's

38 Approved by BCUC Order No. G-143-06.

obligations under sections 45(6.1)(a) and (c) of the UCA. BC Hydro will notify stakeholders of these filings. For greater certainty, these filings and any filings made pursuant to paragraphs 20 and 21 will not preclude Parties from raising prudency issues under the UCA with respect to costs incurred or to be incurred.

20. BC Hydro will file Major Threshold Project applications for determinations under section 45(6.2)(b) of the UCA in regard to Major Threshold Projects that are ready to proceed, supported by detailed ("CPCN-like") business cases. BC Hydro will notify stakeholders of these applications at the time they are filed. Major Threshold Projects are all capital projects with gross project costs, including contributions in aid of construction, without limitation transmission interconnection costs and upgrades and the amount of any First Nations costs attributable to the relevant project, greater than $50 million, plus other projects which BC Hydro believes should have Major Threshold Project application treatment. The Commission will determine whether or not to hold a hearing into such an application, and may designate any process to review Major Threshold Project applications as available under section 45 of the UCA. Equally for straightforward projects the Commission may choose not to hold a hearing.

21. Projects in Capital Plans or Major Threshold Project applications designated as requiring a CPCN by the Commission under section 45(5) of the UCA, or requested by BC Hydro, will be filed as CPCN applications. BC Hydro will notify stakeholders of these applications at the time they are filed. The Commission can request additional information regarding any project to decide if an order under section 45(5) is warranted.

22. The intent of sections 19-21, above, is that stakeholders will have adequate information to propose to the Commission the appropriate process for review of each capital project or expenditures.

The F07/F08 RRA NSA capital plan and major threshold project application provisions were grounded on sections 45(6.1) and 45(6.2) of the *UCA*. On May 1, 2008, sections 45(6.1) and 45(6.2) of the *UCA* were repealed and replaced by sections 44.1 and 44.2 pursuant to the *Utilities Commission Amendment Act, 2008* (***2008 UCA Amendments***), thereby removing the statutory basis of section 19 and 20 of the NSA. As a result, in both the F09/F10 RRA[39] and 2008 LTAP proceedings,[40] BC Hydro committed to providing its view on an appropriate capital plan review process as part of its 2008 LTAP proceeding. No intervenor opposed

[39] Exhibit B-19 of the F09/F10 RRA proceeding.

[40] Second Procedural Conference of 27 November 2008, Transcript Volume 2, pages 130 to 132.

BC Hydro's decision to address the capital plan review process as a 2008 LTAP issue.[41] BC Hydro held a workshop on December 10, 2008 attended by intervenors and BCUC staff, outlining its proposed capital plan review process, which is described below. A copy of the capital plan review process-related materials distributed at the workshop are attached as Attachment 4 to this Evidentiary Update.

BC Hydro proposes that the language and commitments agreed to in sections 19 through 21 of the F07/F08 RRA NSP remain essentially the same, as further described below.

4.2 Capital Plan Review Process

BC Hydro is of the view that the purpose of its capital plan is to: (1) satisfy the requirements of the *UCA* while maintaining flexibility to address unique situations; (2) present the scope and magnitude of all BC Hydro capital plans in one place; (3) provide a single reference for BC Hydro's capital projects; and (4) minimize regulatory burden.

BC Hydro's most recent capital plan was submitted to the BCUC as part of BC Hydro's F09/F10 RRA. This capital plan consists of:

- A chapter providing the context for BC Hydro's capital plan, including information on the capital planning and budgeting process for the utility, a description of the capital expenditures by business function, and a review of past capital expenditures;

- A list of all projects with a gross estimated cost greater than $2 million, detailing for each project: actual expenditures to date; planned expenditures in the next two fiscal years; and an estimate of total project costs; and

- A project description for each capital project with a gross estimated cost greater than $5 million, summarising the project, its key drivers, the issues it addresses, and any alternatives to the project.

Since this capital plan was developed and filed prior to the enactment of the *2008 UCA Amendments*, it was developed to be consistent with section 19 of the NSA.

41 *Ibid*.

Going forward, BC Hydro proposes to continue to file capital plans bi--annually as part of its future RRAs. The information provided in these future capital plans will be consistent with the capital plan filed in the F09/F10 RRA. BC Hydro is of the view that this approach, consistent with paragraph 19 of the NSA, provides the BCUC and intervenors with sufficient details on BC Hydro's planned capital expenditures.

4.3 Threshold for Major Threshold Project Applications

The *2008 UCA Amendments* repealed sections 45(6.1) and 45(6.2), and replaced these provisions with sections 44.1 and 44.2 of the *UCA*. Section 44.2 of the *UCA* addresses the filings by public utilities, and review of, expenditure schedules for capital expenditures, DSM expenditures and expenditures for the acquisition of energy from others.

One important distinction between the repealed sections 45(6.1) and 45(6.2) and the enacted section 44.2 is that whereas sections 45(6.1) and 45(6.2) required a public utility to file plans for capital expenditures, DSM and the acquisition of energy ("A public utility must file…"), section 44.2 is permissive ("A public utility may file…") with regard to a public utility filing with the BCUC its expenditure schedule for capital expenditures and the acquisition of energy.

While section 44.2 of the *UCA* is permissive, BC Hydro is of the view that it is still appropriate to file applications for major capital projects pursuant to section 44.2(1)(b) of the *UCA*. The threshold BC Hydro will use for these major threshold projects, consistent with paragraph 20 of the NSA, is $50 million. In these major threshold project filings, BC Hydro will seek acceptance from the BCUC that the project expenditures are in the public interest under section 44.2(3)(a) of the *UCA*. All major threshold project applications will be consistent with the BCUC's *Certificate of Public Convenience and Necessity CPCN Application Guidelines*.[42]

For additional clarity, with the exception of DSM (discussed below), BC Hydro will bring forward all capital projects, be it generation, distribution, or other projects, such as properties or information technology, where BC Hydro plans to seek, or has obtained, BC Hydro Board of Directors approval of a project expenditure of $50 million or more. In the

[42] BCUC Order No. G-28-04 dated March 31, 2004.

case of generation projects, for those major threshold projects where the driver is growth, BC Hydro will, for regulatory efficiency, seek BCUC approvals as part of its LTAP filings when the project schedule permits. Where project schedule does not permit, or where the project driver is related to safety, reliability, or some other reason, BC Hydro expects to file individual project applications.

For expenditures related to DSM BC Hydro will file pursuant to section 44.2(1)(a) of the *UCA*, and seek approval from the BCUC for DSM expenditures per section 44.2(3)(a) of the *UCA*. DSM expenditure requests will be contained in BC Hydro's LTAPs.

5 Heritage Contract

On November 28, 2008, the B.C. Cabinet signed OIC No. 849/2008 into a regulation, establishing the Heritage Contract in perpetuity and formally legislating Policy Action No. 16 of the 2007 Energy Plan, which provides: "establish the existing heritage contact in perpetuity". A copy of OIC No. 849/2008 is attached to this Evidentiary Update as Attachment 5.

The Heritage Contract arose from the B.C. Government's 2002 Energy Plan and was developed based on the following:

- The Terms of Reference issued on March 11, 2003 to the BCUC by OIC No. 0253 that established the Heritage Contract inquiry;
- BC Hydro's April 30, 2003 Proposal Regarding a Heritage Contract, Stepped Rates and Access Principles; and
- The BCUC's response to that proposal and the evidence it heard in the course of the hearing into it, being the October 17, 2003 Report and Recommendations.

The Heritage Contract became law through the *BC Hydro Public Power Legacy and Heritage Contract Act*,[43] and Special Direction No. HC2 to the BCUC (**HSD#2**), which is described at section 1.2.3 of the 2008 LTAP.[44] The Heritage Contract ensures the electricity generated from the Heritage Assets continues to be available to BC Hydro ratepayers based

[43] S.B.C. 2003, c.86.

on cost of service, not market price. The Heritage Contract is attached as Appendix A to HSD#2.

An important element of the Heritage Contract is that BC Hydro's rates are established on a cost of service basis (paragraph 5(d) of HSD#2). This means that BC Hydro's customers get the full benefit of the Heritage Assets, subject to the $200 million cap on Trade Income. Another key element is the principle that new customers also be permitted to benefit from low-cost Heritage Assets, as shown on Schedule B to the Terms of Reference attached to the BCUC's Heritage Contract Report and Recommendations as Attachment A.

[44] Exhibit B-1, page 1-13, lines 1-4 to page 1-4, lines 1--4.

BRITISH COLUMBIA
UTILITIES COMMISSION

ORDER
NUMBER G-

SIXTH FLOOR, 900 HOWE STREET, BOX 250
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IN THE MATTER OF
the Utilities Commission Act, R.S.B.C. 1996, Chapter 473

and

An Application by British Columbia Hydro and Power Authority (BC Hydro)_
(Name of Application)

BEFORE: ________, Commissioner _________________, 2009

O R D E R

WHEREAS:

A. British Columbia Hydro and Power Authority ("BC Hydro', the "Applicant") filed its 2008 Long-Term Acquisition Plan (the "LTAP", the "Application") on 12 June 2008 pursuant to sections 44.1 and 44.2 of the Utilities Commission Act (the "Act"); and

B. BC Hydro in the filing applies for an order which states that the 2008 LTAP is in the public interest pursuant to section 44.1(6)(a) of the Act and pursuant to section 44.2(3)(a), determines that expenditures related to the programs and projects listed in section 1.1.2 of the Application are in the public interest; and

C. The Commission has considered the Application, evidence, and submissions of intervenors and the Applicant.

. . ./2

NOW THEREFORE the Commission orders as follows:

1. The 2008 LTAP is in the public interest under subsection 44.1(6)(a) of the Act and the Commission endorses:

   - The proposed Clean Power Call pre-attrition target of ~~5,000~~ 3,000 gigawatt hours per 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* 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 of dependable capacity and 3,000 GWh/year of firm energy until at least F2019;

   - ~~The residential Low Income demand side management ("DSM") program, which has a Non-Participant Test benefit-cost ratio of 0.6 and an All Ratepayers benefit-cost ratio of 0.9;~~

   - The rescission of Directives 62 and 64 of the Commission'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 Commission's decision concerning BC Hydro's 2006 Integrated Electricity Plan/LTAP to provide that DSM performance reports, as described in Directive 16, will be filed with the Commission on an annual basis;

   - BC Hydro's amortization period for deferred DSM expenditures is to remain at 10 years;~~.~~

   - The proposed capital plan review process including the review of major threshold projects and expenditures related to DSM.

2. Pursuant to section 44.2(3)(a) of the Act, the following expenditures are determined to be in the public interest:

- Expenditures of $418 million required to implement BC Hydro's DSM Plan in F2009, F2010 and 2011;

- Expenditures of $600,000 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 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;

- Expenditures of $ 140.1 million in F2009 – F2012 required to complete the Definition phase work for, and implement, the Fort Nelson Generating Station Upgrade Case 3.2.

  In the alternative, BC Hydro seeks a determination that expenditures of $94.5 million to complete the Definition phase work for, and implement, the Fort Nelson Generating Station Upgrade Case 2 are in the public interest under subsection 44.2(3)(a) of the Act;

- Approves the submission of the LTAP Contingency Resource Plans for inclusion in BC Hydro's Network Integration Transmission Service update.

DATED at the City of Vancouver, in the Province of British Columbia, this day of ________ 2009

BY ORDER

Clean Power Call Proposals

On November 25, 2008, BC Hydro received 68 proposals from 43 registered Proponents in response to the Clean Power Call RFP.

In aggregate the 68 proposals represent a total firm energy output of approximately 17,000 GWh/year from 45 hydro projects, 19 wind projects, two waste heat projects, one biogas project, and one biomass project.

This information is provided for informational purposes only and does not constitute any acknowledgement or representation by BC Hydro as to project eligibility.

Proponent Name	**Nearest City**
AltaGas Ltd.	Sparwood Stewart
Anderson River Hydro Ltd., a wholly-owned subsidiary of Canadian Hydro Developers, Inc.	Spuzzum
Atla Energy Corporation	Mica
AXOR GROUP Inc.	Tumbler Ridge
Box Canyon Hydro Corporation - Sound Energy Inc. Co-ownership	Port Mellon
Castle Mountain Hydro Ltd	McBride
C-Free Power Corp.	Gold Bridge
Cloudworks Energy Inc.	Campbell River Harrison Hot Springs Mission
Confederation Power Hydro Limited Partnership	Kitsault
Creek Power Inc.	Pemberton
EarthFirst Canada Inc.	Chetwynd Tumbler Ridge
ENMAX Syntaris Bid Corp. (an Affiliate of Syntaris Power Corp.)	Squamish Terrace Chilliwack
EPCOR Power Development (British Columbia) Limited Partnership	Tumbler Ridge
Finavera Renewables Inc.	Tumbler Ridge Chetwynd
Fosthall Creek Power Limited Partnership	Nakusp
GREENGEN HOLDINGS LTD dba PACIFIC GREENGEN POWER	Douglas IR/Harrison Hot Springs
Hackney Hills Wind Limited Partnership	Hudson's Hope/Upper Halfway
HAWKEYE Energy Corporation	Powell River

Proponent Name	Nearest City
Hurley River Hydro LP	Pemberton
Hydromax Energy Ltd.	Gibsons Sechelt
Island Cogeneration No. 2 Inc.	Campbell River
Kleana Power Corporation	Campbell River
Kwagis Power Limited Partnership	Port McNeill
Long Lake Joint Venture	Stewart
Lytton Wind Energy Joint Venture	Lytton Town
Naikun Wind Generating Inc.	Port Edward
North Coast Wind Energy Corp.	Prince Rupert
Plutonic Power Corporation and GE Energy Financial Services Company	Powell River
Powerhouse Developments Inc. (an Affiliate of Sea Breeze Power Corp.)	Christina Lake
Premier Renewable Energy Ltd.	Fernie Lytton
Purcell Green Power Inc.	Meadow Creek
Robson Valley Power Corporation	McBride
Run of River Power Inc.	Squamish Pitt Meadows
Ryan River Joint Venture	Pemberton
Sea Breeze Energy Inc. (an Affiliate of Sea Breeze Power Corp.)	Port Hardy
Selkirk Power Company Ltd.	Golden
SkyPower Corp.	Vanderhoof
Stlixwim First Project Corp.	Sechelt
Stlixwim Partnership	Sechelt
Swift Power Corp.	Terrace
Thunder Mountain Wind Limited Partnership	Tumbler Ridge
Vanport Ecologies Inc.	Fort Nelson Britannia Mines Jordan River
Westface Energy Inc.	Prince George

CAPP
CANADIAN ASSOCIATION
OF PETROLEUM PRODUCERS

December 15, 2008

Mr. John Rich, P.Eng, MBA
Manager
Generator Interconnections & Transmission Services
Energy Planning
BCHydro
333 Dunsmuir Street, 10th floor
Vancouver, B.C. V6B 5R3

Dear Mr. Rich:

Re: The Canadian Association of Petroleum Producers (CAPP) Electric Load Potential Forecast for Horn River Basin Shale Gas in Support of Ft. Nelson LTAP

The potential exists for significant electric load growth in the greater Ft. Nelson Horn River Basin (HRB) area within the range of 100-350 Megawatts (MW) by the year 2020. This is due to the development potential of the Horn River Basin Shale Gas. The gas production "best guess" forecast from the Horn River Basin play is anticipated to be approximately 2.7 bcf/d (billion cubic feet / day) by 2020

The electrification of HRB field compression and Carbon Capture and Sequestration (CCS) compression at the Cabin Plant and area processing plants are major opportunities to abate GHG emissions. The potential exists to reduce cumulative emissions of some 100 Megatonnes via electrification and CCS from this play by the year 2030. The range of electric load potential of ~ 100 – 350 MW exists based principally on the timing of electrification.

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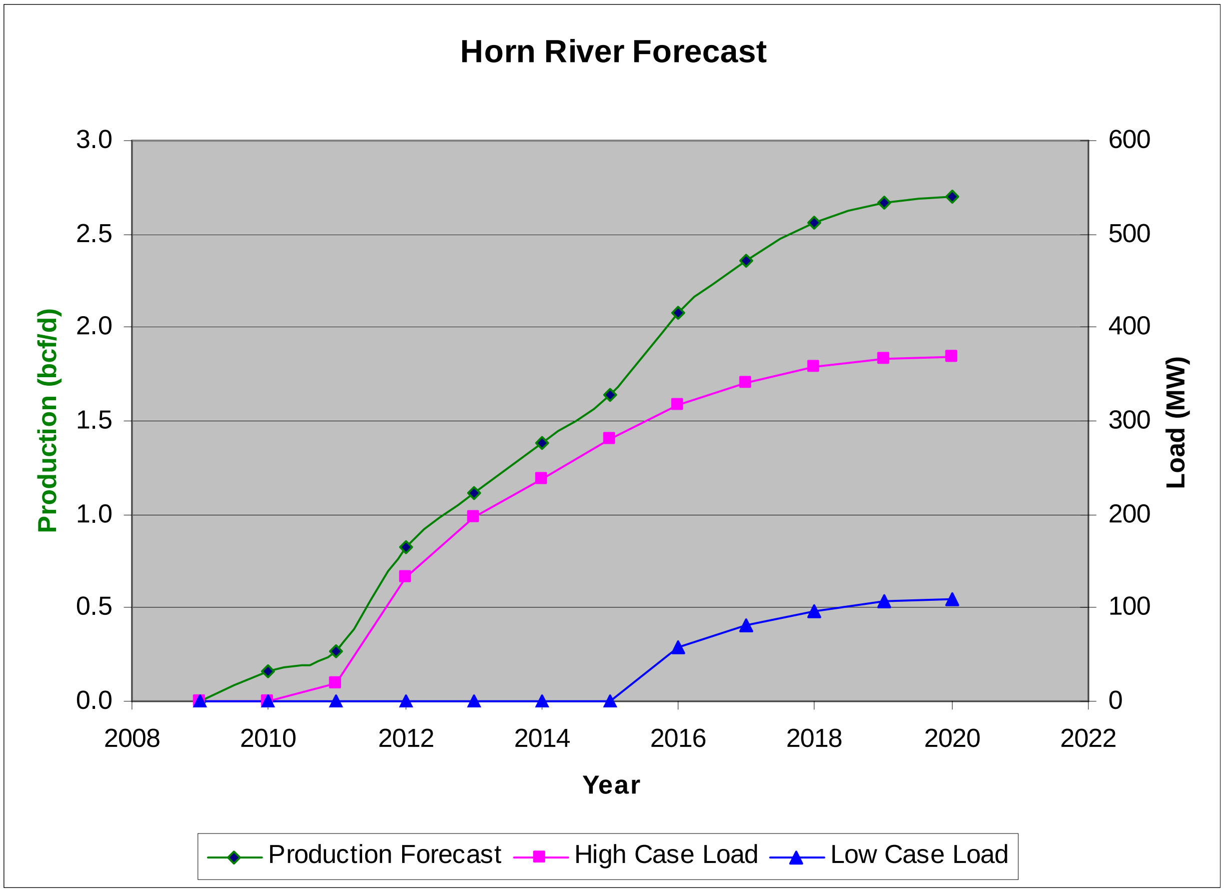


Figure. 1

Play Back Ground

The Horn River Basin Shale Gas play has developed over the last three to four years. Mineral Land Tenure Licenses totaling over 1.2 million acres have been issued by the Province of B.C. The revenue to the Crown associated with these licenses now totals over 1.5 Billion dollars.

The majority of the tenure is held by a group of eight Operators who have formed a producers association named the Horn River Producers Group (HRPG). The charter of the HRPG is to work cooperatively to facilitate the orderly development of the resource. The Operators and outlines of their land holdings are as indicated in **Figure 2**.

The Canadian Association of Petroleum Producers (CAPP), through its Oil & Gas Sector Table established by the B.C. government, have been working with the B.C. Ministry of Energy, Mines and Petroleum Resources in assessing the impact of this resource development in terms of greenhouse gas emissions and the potential for abatement. The information obtained is being reported to the Climate Committee of the B.C. Cabinet. A primary opportunity to reduce the anticipated emissions from natural gas production and development is the electrification of the HRB field gathering compression and CO_2 sequestration compression at the major plant facilities.

The following information is provided as scoping support for the potential electric load growth in the Ft Nelson / Horn River Basin Area and the assumptions and methodology used to derive it.

Horn River Basin Production Forecast

Production from the Horn River Basin shale gas is forecast to grow from approximately 50 mmscf/d (million cubic feet per day) in 2009 to approximately 2,700 mmscf/d by 2020. The forecast is derived from a survey of the area operators of the HRPG which requested their anticipated annual drilling well count and the associated production. The well count derived is approximately 80 in 2009, growing to over 200 wells per year in 2016, then maintaining that level. It is anticipated that there could be a total of 2,200 wells producing in 2020.

It is the nature of shale gas to estimate production from each well using a representative Type Curve. Type curves depict the average initial production rate, the rate of decline and the ultimate expected reserve recovery. The main characteristic of these wells is that the initial producing rate and pressure fall rapidly. Each well will require compression immediately. While the details of each companies type curve assumptions are proprietary and will vary from company to company and area to area, a typical curve is attached as **Figure 3**. The production forecast curve combines the annual growth in production with the declining production base from the existing wells.

Horn River Basin Field Development

The Horn River Basin Shale gas will be developed using horizontal wells from multiple well pads. The number of wells per pad will vary, but will likely start at 8-12. The pads will produce to a low pressure (150 psig) gathering system. The gathering system will transport the well effluent to a Compression and Dehydration Facility, referred to as an RGT facility (Raw Gas Treatment).The gas will then be transported via a high pressure (1,500 psig) gathering system to a Processing Plant. The processing plant removes the CO_2 and H_2S and necessary to meet sales gas specifications. The Process Plant is where CO_2 may be compressed and sequestered. The sales gas is then delivered to the Sales Gas Transmission system. **Figure 4** schematically represents the Production System.

Processing capacity exists initially at the Spectra Ft. Nelson Facility. The Cabin Plant first stage (with a capacity of 400 mmscf/d) will be required by 2011 / 2012 to process the anticipated production volumes. It is anticipated that the Cabin plant will undergo a series of expansions up to an ultimate capacity of 2,400 mmscf/d.

Horn River Basin RGT Facilities

A major opportunity for electric load would result from the electrification of the RGT Facilities. The gathering systems are assumed to operate as low as 100 psig with a required Plant outlet sales pressure of 1,500 psig. The resulting compression load for the average HRB gas composition is 150 HP / mmscf/d. The compression curve for various pressure assumptions and a typical gas composition are displayed in **Figure 5.** The annual compression load growth is determined by the increase, each year, in the compression required to produce the annual growth in gas volumes. **(Table 2)**

Each site would, conceptually, gather and compress from a 10 km radius. The potential volume compressed at each site would be 300 - 500 mmscf/d. The possible RGT sites are depicted in **Figure 2**. They would be situated along the existing Komie Road and its likely extension northward. Full field development would require up to eight such RGT facilities.

Plant Facilities

The other opportunity for load growth would result from electrified compression associated with CO_2sequestration at the proposed Cabin Plant. The Cabin Plant is anticipated to be built in 6 stages, with each stage representing process capacity of 400 mmscf/d. The ultimate capacity would be 2,400 mmscf/d. The first stage is anticipated to be in service for September 2011. The final stage will be required by May of 2105. **Figure 6** depicts the timing of the Cabin Plant stages and process capacity growth.

Each Plant stage would remove 48 mmscf/d of CO_2. This volume would require 15,000 Hp (11 MW) to sequester the CO_2 in the subsurface. This estimate assumes compression from 15 psig to approximately 2,400 psig (330 HP/mmscf/d). It is anticipated that, with other services, each plant stage would utilize a total 20 MW of load

Accordingly, given six plant stages, the Ultimate potential load for the Cabin Plant is 120 MW.

Sales gas transmission from the Cabin Plant will be via an expansion of the TCPL system.

Potential Electric Load

The range of electric load potential of some 100 - 350 MW is summarized in Table 1 below. It results from assumptions concerning the timing of electrification. The conclusion is that the earlier that power can be brought to the area, the higher the load potential, thereby providing the largest benefit from a GHG mitigation perspective.

Table 1

Horn River Electric Load Scenarios

Year	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
High Case Load (MW):												
Gathering / RGT	0	0	0	92	117	139	160	198	221	238	247	249
Plant	0	0	20	40	80	100	120	120	120	120	120	120
Total	**0**	**0**	**20**	**132**	**197**	**239**	**280**	**318**	**341**	**358**	**367**	**369**
Low Case Load MW):												
Gathering / RGT	0	0	0	0	0	0	0	37	61	77	87	89
Plant	0	0	0	0	0	0	0	20	20	20	20	20
Total	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**57**	**81**	**97**	**107**	**109**

The High Case Load (~ 350 MW total) assumes power is available in 2011. The case assumes that all (120 MW) of Cabin Plant is ultimately electrified, 90 MW of existing compression at RGT sites is retrofitted, and 75% of the go forward load growth from 2012 onwards (160 MW) is electrified.

The Low Case Load (~ 100 MW total) assumes power is available in 2016. The case assumes that only 20 MW of Cabin Plant is ultimately electrified, existing compression at RGT sites is not retrofitted, and 75% of the go forward load growth from 2016 onwards (90 MW) is electrified.

If you have any questions with respect to the information provided please contact Dan Brown at (403) 645-5336

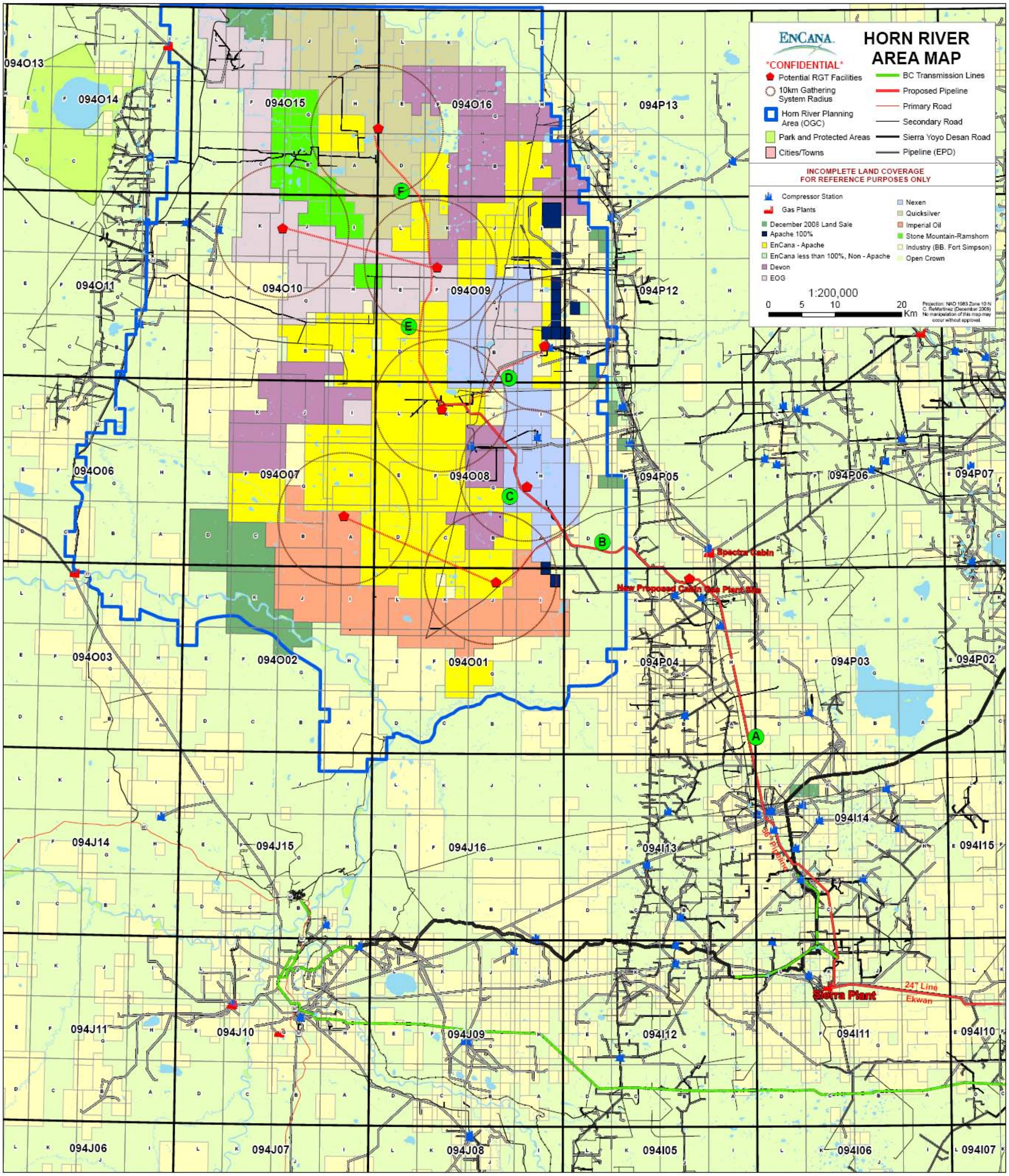
Sincerely,

Brad Herald

Brad Herald
Manager, BC Operations

Figure. 2 Horn River Basin Area Map

- **See below**


HORN RIVER AREA MAP
CONFIDENTIAL
Potential RGT Facilities
10km Gathering System Radius
Horn River Planning Area (OGC)
Park and Protected Areas
Cities/Towns
BC Transmission Lines
Proposed Pipeline
Primary Road
Secondary Road
Sierra Yoyo Desan Road
Pipeline (EPD)
INCOMPLETE LAND COVERAGE FOR REFERENCE PURPOSES ONLY
Compressor Station
Gas Plants
December 2008 Land Sale
Apache 100%
EnCana - Apache
EnCana less than 100%, Non - Apache
Devon
EOG
Nexen
Quicksilver
Imperial Oil
Stone Mountain-Ramshorn
Industry (BB. Fort Simpson)
Open Crown
1:200,000
0 5 10 20 Km
Projection: NAD 1983 Zone 10 N
C. ReMartinez (December 2008)
No manipulation of this map may occur without approval.
094O13
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Spectra Cabin
New Proposed Cabin Gas Plant Site
Sierra Plant
24" Line
Ekwan

Figure 3. Horn River Basin Typical Type Curve

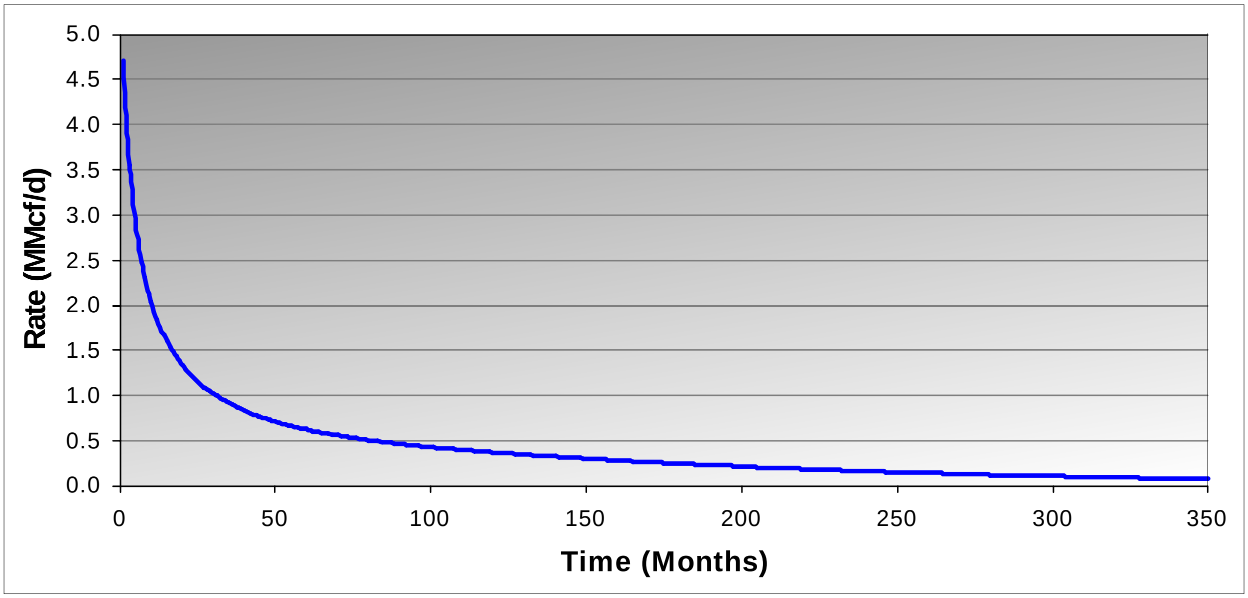


Figure 4 Horn River Basin Field Production Schematic

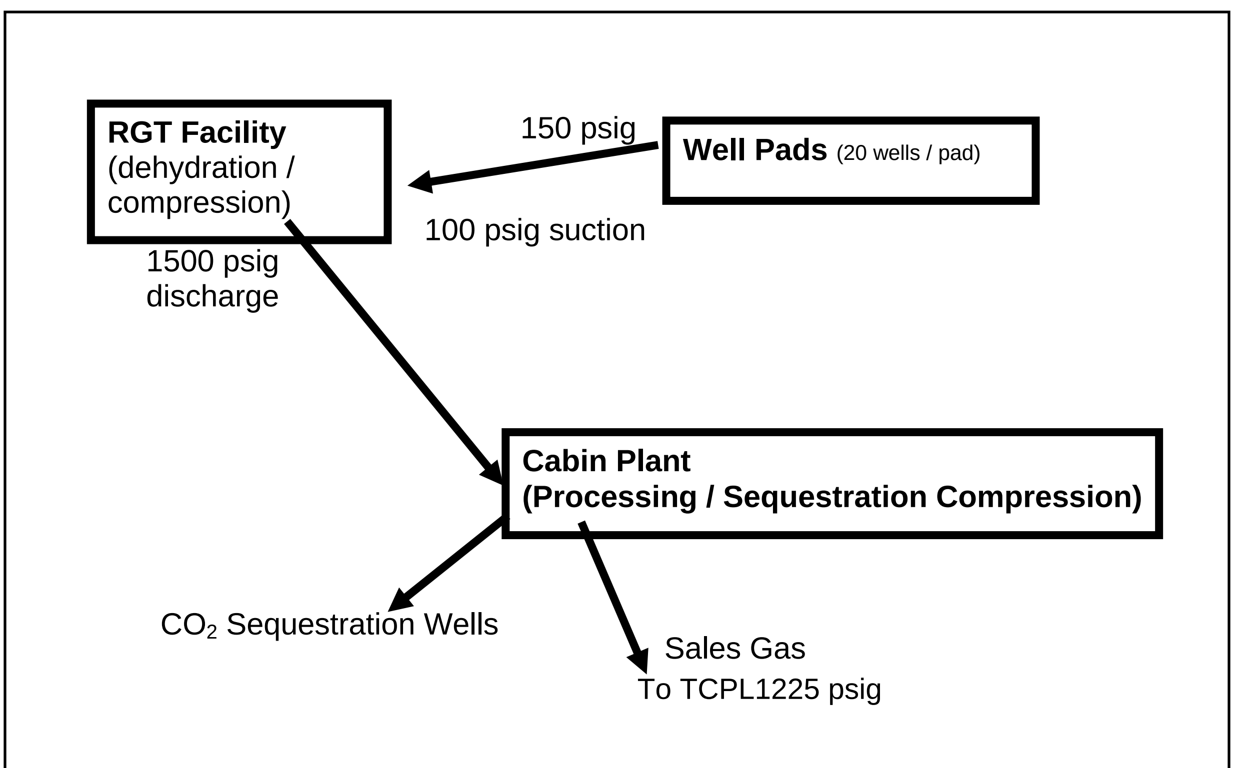


Figure 5 Horn River Basin RGT Compression Power Requirements

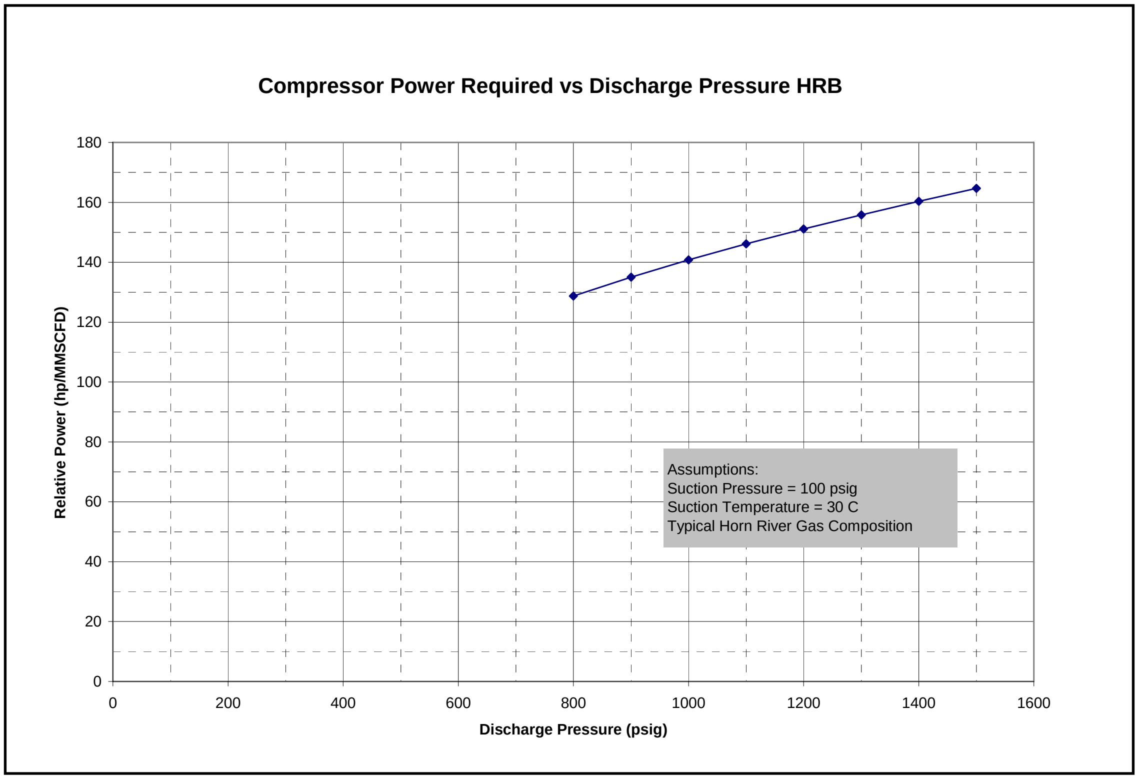


Figure 6 Cabin Plant Estimated Stage Addition Timing / Capacity Profile

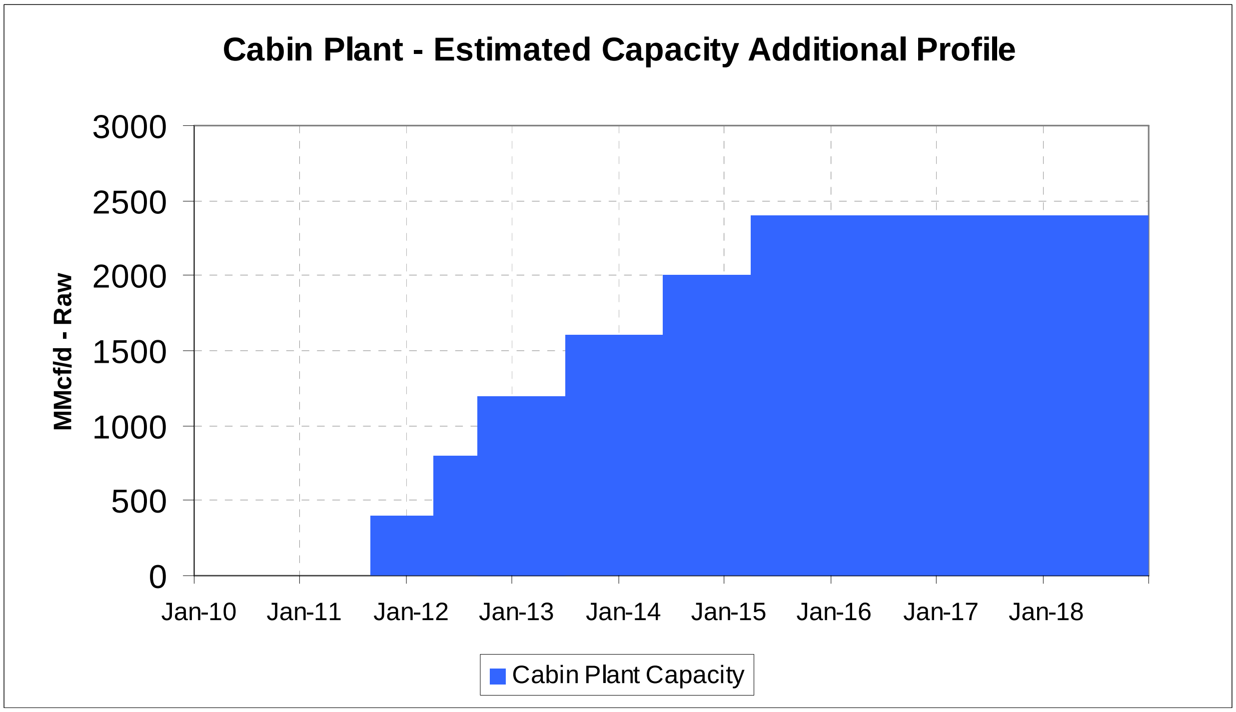


Table. 2

HRB Compression and Electric Load Growth

Forecast – Best Guess - Bcf/d (From CAPP)

	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
HRB	0.110	0.163	0.273	0.821	1.118	1.380	1.637	2.082	2.360	2.560	2.665	2.695

New Prod	Production add by year (bcf/d)											
	2009	**2010**	**2011**	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**
HRB	0.000	0.163	0.110	0.548	0.298	0.262	0.257	0.445	0.279	0.196	0.111	0.027
	Cum production adds (bcf/d)											
HRB	0.000	0.163	0.273	0.821	1.118	1.380	1.637	2.082	2.361	2.557	2.668	2.695
New hp	**RGT** hp adds needed by year (@ 100% electrification)											
HRB	-21	24465	16451	82203	44647	39233	38542	66720	41908	29374	16624	4119
	Cum **RGT** hp adds needed (@ 100% electrification)											
HRB	-21	24444	40895	123097	167744	206977	245519	312239	354147	383521	400144	404263
Load (kW)	**RGT**(@ 100% electrification)											
HRB	-16	18258	12277	61345	33318	29279	28762	49791	31275	21921	12406	3074
	Cum **RGT** kW adds needed (@ 100% electrification)											
HRB	-16	18242	30518	91864	125182	154461	183223	233014	264289	286209	298615	301689

Horn River Electric Load Scenarios

	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
High Case Load (kW):												
Gathering	0	0	0	91,864	116,852	138,811	160,383	197,727	221,183	237,623	246,927	249,233
Plant	0	0	20,000	40,000	80,000	100,000	120,000	120,000	120,000	120,000	120,000	120,000
Total	**0**	**0**	**20,000**	**131,864**	**196,852**	**238,811**	**280,383**	**317,727**	**341,183**	**357,623**	**366,927**	**369,233**
Low Case Load (kW):												
Gathering	0	0	0	0	0	0	0	37,343	60,799	77,240	86,544	88,849
Plant	0	0	0	0	0	0	0	20,000	20,000	20,000	20,000	20,000
Total	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**57,343**	**80,799**	**97,240**	**106,544**	**108,849**
Well Count:												
20	80	110	134	143	156	173	188	224	230	240	245	240
20	**100**	**210**	**344**	**487**	**643**	**816**	**1004**	**1228**	**1458**	**1698**	**1943**	**2183**

Bioenergy Call Filing and Capital Plan Review Process

2008 LTAP Intervenor Discussion

December 10, 2008

BChydro

AGENDA

1. Welcome & Introduction
2. Bioenergy Call Filing
3. Capital Plan Review Process

Bioenergy Call
Phase I RFP
Section 71 Filing

Outline of Section 71 Report

BChydro

1. Background and Order Requested
2. Call Implementation and Evaluation
3. First Nations and Stakeholder Engagement
4. Need for Bioenergy Call
5. Cost Effectiveness

Appendices: Include RFP, Specimen EPA, submission listing and jurisdictional comparison

2007 BC Energy Plan

BC hydro

- The provincial government's 2007 BC Energy Plan contains the following policy actions:
  - Action No. 1 – self sufficiency;
  - Action No. 18/19/20 – zero net GHG emissions;
  - Action No. 21 – 90% clean or renewable electricity;
  - Action No. 22 – replacement of firm Burrard energy;
  - Action No. 30 – introduction of Bioenergy Strategy.

Special Direction No. 10

BC hydro

In its section 71 consideration of the public interest regarding the awarded biomass contracts, the BCUC must be primarily guided by the following factors which provide material value to ratepayers:

(a) reduced risk of future costs associated with GHGs that contribute to global climate change;

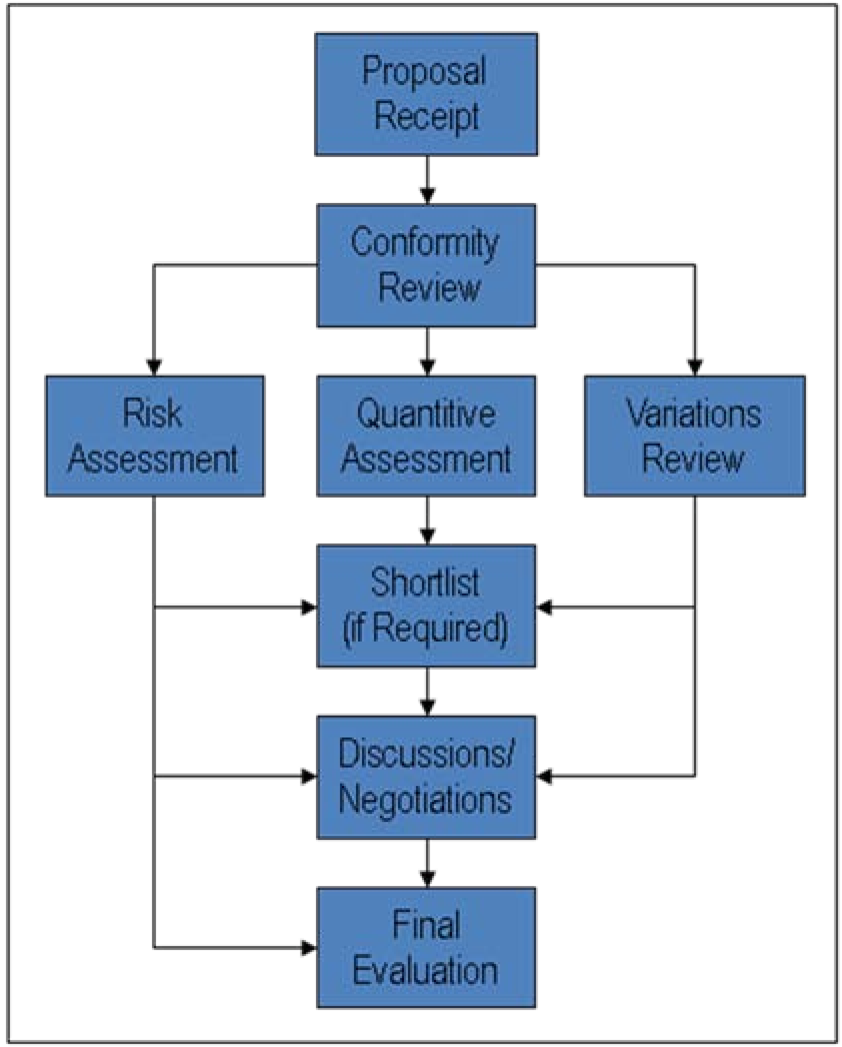
(b) contribution of biomass energy to the diversification of BC Hydro's electricity supply portfolio;

(c) assistance in meeting BC Hydro's capacity requirements.

Stakeholder Engagement Process

- RFEOI issued in March 2007 to identify potential bioenergy projects; received over 80 submissions.
- August 2007 – met with government and industry to discuss upcoming call and impact on existing users of residual wood.
- Information sessions held following RFP issuance (Feb. 6/08):
  - Feb. 20 – assist stakeholders to assess potential participation;
  - March 26 – feedback on terms/conditions and RFP evaluation;
  - May 28 – guidance workshop for registered proponents.
- First Nations engagement:
  - several meetings held with First Nations Forestry Council.

RFP Implementation Process



Proposal Evaluation & Selection

Note: EPAs with selected proponents have not yet been signed

- BC Hydro received 20 project proposals from 13 different proponents for about 4,100 GWh/year of firm energy
- BC Hydro conducted a Risk Assessment to assess development and delivery risks associated with the projects
- Based on a preliminary evaluation, BC Hydro conducted initial discussions with a subset of bidders; subsequent negotiations with selected proponents resulted in increased value for ratepayers
- In December 2008, BC Hydro selected 4 projects (579 GWh/year) for EPA awards based on contract terms and pricing
- Awarded volume is considerably below the 1,000 GWh/year target

Product Being Acquired

BC hydro

- Energy being acquired is virtually all firm energy; the quantity of non-firm energy is minimal.
- Proponents were allowed to bid firm energy on either an hourly or seasonal basis.
- For the awarded EPAs, two proponents chose hourly firm energy while the other two proponents opted for seasonally firm energy.
- Given certain EPA provisions and the nature of the projects, all four projects are viewed as providing both energy and capacity value.

Cost Effectiveness of EPA Awards BChydro

- Competitive RFP Process:
  - Received 20 proposals for 4 times the targeted energy volume.
- Jurisdictional Comparison:
  - Limited number of biomass call processes in North America;
  - Recent contract awards in California at US$92-$102/MWh.
- Market Pricing:
  - Spot market price is not a valid comparator;
  - 5-year market forward prices are lower than EPA prices but do not offer fixed pricing for longer term duration.
- Alternate Resources:
  - Comparison to generic wind, hydro and CCGT projects.

EPA Awards and Pricing

BC hydro

- Total volume awarded is significantly less than the 1,000 GWh/year target
- Term of the EPAs ranges from 8 to 15 years
- BC Hydro takes no fuel cost risk in any of the EPAs
- Average ABP for Bioenergy Call awards is slightly higher than for F2006 Call Large Projects after adjustment for CPI escalation and green attributes

Proposed Regulatory Review

BC Hydro proposes a written process with the following key dates:

Action	Target Date
Target Filing	December 22, 2008
BCUC and Intervenor IRs	January 8, 2009
BC Hydro Responses to all IRs	February 10
BC Hydro's Submission	March 13
Intervenor Submissions	March 27
BC Hydro's Reply	April 3

Capital Plan Review Process

Objectives of Review Process

BC hydro

- Satisfy requirements of the Utilities Commission Act.
- Maintain flexibility to address unique situations.
- Present the scope and magnitude of all BC Hydro capital plans in one place (providing a single window into BC Hydro capital projects).
- Minimize regulatory burden for all.

Background

- BC Hydro proposed a capital review framework in the F07/F08 RRA that was intended to provide fulsome, timely information regarding capital plans.

- Per the F07/F08 RRA NSA sections 19, 20 and 21, BC Hydro committed to file :
  - bi-annual capital plans pursuant to section 45(6.1)(a) of the UCA (compliance filing);
  - major threshold projects costing more than $50 million (“CPCN like”) pursuant to section 45(6.2)(b) of the UCA (seeking a determination);
  - CPCN applications as required under section 45(5) or as applied for by BC Hydro.

Current Filings

- The capital plan filing within the F09/F10 RRA is consistent with BC Hydro's capital plan review proposal:
  - Includes all capital expenditures, with estimated costs provided (Chapter 5);
  - Projects whose total cost >$2 million are listed individually (Appendix I);
  - Projects whose total cost >$5 million are described in more detail (Appendix J).

- Major threshold projects are filed when and where it makes sense (e.g. Fort Nelson Generation Upgrade – filed in conjunction with the 2008 LTAP).

2008 UCA Amendment Act

BChydro

- With the issuance of the *2008 UCA Amendment Act*, section 45(6.1) & 45(6.2) were repealed, removing the statutory basis of section 19 and 20 of the F07/F08 RRA NSA.

- The *2008 UCA Amendment Act* now includes section 44.2, a permissive section which sets out that utilities may provide schedules for DSM expenditures, capital plans and plans for acquiring energy from others.

UCA section 44.2 - Expenditure Schedule

BC hydro

- After reviewing an expenditure schedule, the BCUC must accept or reject it (or part of it) as being in the public interest.

- The BCUC considers the following in this review:
  - The government's energy objectives;
  - The most recent LTAP filing;
  - The interests of persons in British Columbia who receive or may receive service;
  - If the schedule includes expenditures on demand-side measures, whether the demand-side measures are cost-effective within the meaning prescribed by regulation.

Capital Plan Review Proposal

- BC Hydro will continue to file bi-annual capital plans in the same form and detail as the capital plan filed as part of the F09/F10 RRA (Chapter 5, Appendix I and Appendix J), as per section 19 of the F07/F08 RRA NSA.

- BC Hydro will file major threshold project applications pursuant to section 44.2(1)(b) for capital projects which have received BC Hydro Board approval for implementation phase expenditures of $50 million or more.

Major Threshold Project Applications

BC hydro

- Major threshold project parameters:
  - – Total gross project expenditures >$50M;
  - – At point where project is ready to proceed – typically at close of definition phase (following Board approval);
  - – Relates to 'projects' not 'programs' – but major projects within a program would qualify;
  - – Covers all capital expenditures, including generation, distribution, and other such as IT and properties;
  - – Detailed business case justifications will be filed per the BCUC's CPCN Application Guidelines.

- In 2009, BC Hydro is expecting to file 10 major threshold project applications.

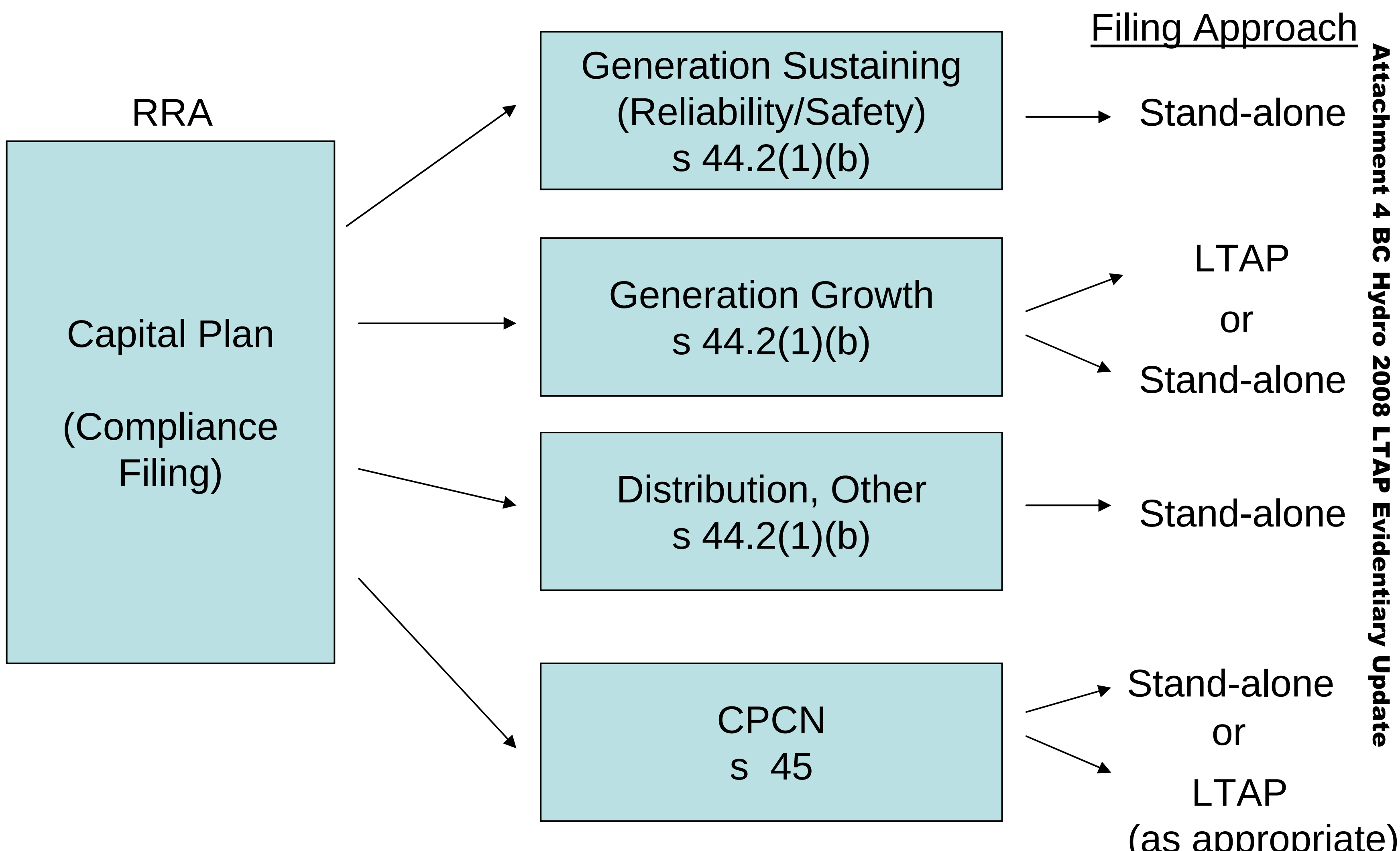
Major Threshold Project Applications for 2009

BChydro

Project	Estimated Filing Date	Project Driver
Bridge River 5/6	Spring 2009	Reliability
Stave Falls Spillway Gates	June 2009	Safety Reliability
Mica Switchgear	June 2009	Reliability
Keenleyside Spillway Gates	July 2009	Safety Reliability
Smart Metering Infrastructure	July 2009	Legislated
Cheakamus Generator	Summer 2009	Reliability
Strathcona Seismic & Seepage	Summer 2009	Safety
Ruskin Dam & Powerhouse	September 2009	Safety Reliability
GMS Unit 1-5 Turbines	September 2009	Reliability
Mica Unit 5/6	October 2009	Growth

Overview of Relationship between Plans and Review Processes

BC hydro



PROVINCE OF BRITISH COLUMBIA

ORDER OF THE LIEUTENANT GOVERNOR IN COUNCIL

Order in Council No. 849 *, Approved and Ordered* NOV 27 2008

Lieutenant Governor

Executive Council Chambers, Victoria

On the recommendation of the undersigned, the Lieutenant Governor, by and with the advice and consent of the Executive Council, orders that section 11 (2) of Appendix A to the Heritage Special Direction No. HC2 to the British Columbia Utilities Commission, B.C. Reg. 158/2005, is repealed.

DEPOSITED
NOV 28 2008
B.C. REG. 335/2008

Minister of Energy, Mines and Petroleum Resources

Presiding Member of the Executive Council

(This part is for administrative purposes only and is not part of the Order.)

Authority under which Order is made:

Act and section:- *BC Hydro Public Power Legacy and Heritage Contract Act*, SBC 2003, c. 86, s. 4

Other (specify):- oic 1123/2003

October 28, 2008 R/1141/2008/27

Figure 1 Energy Load / Resource Balance Amended Base Resource Plan

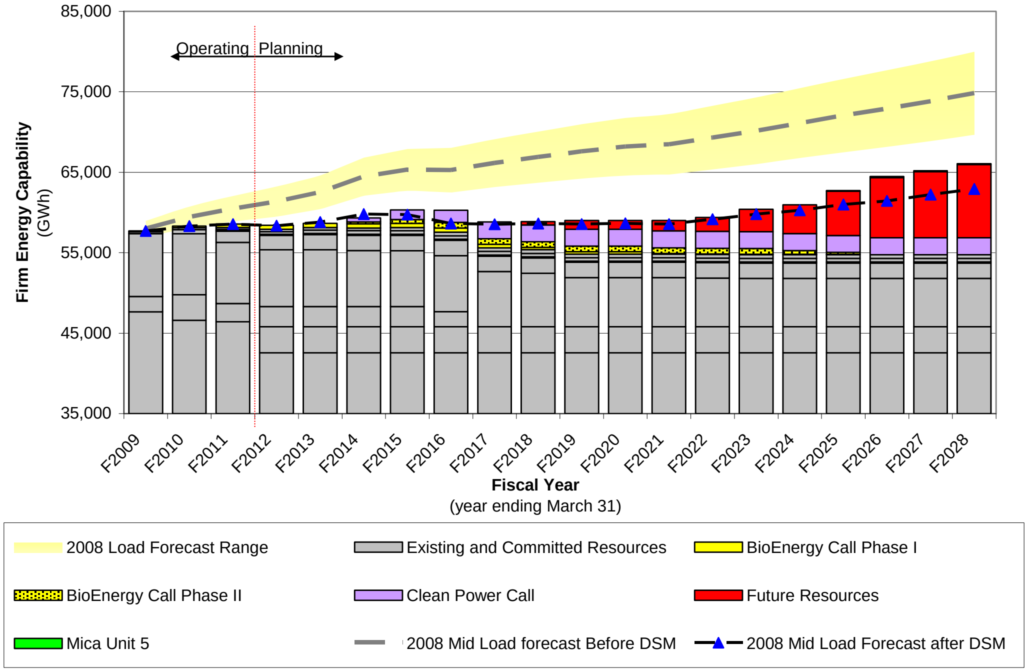


Figure 2 Capacity Load / Resource Balance Amended Base Resource Plan

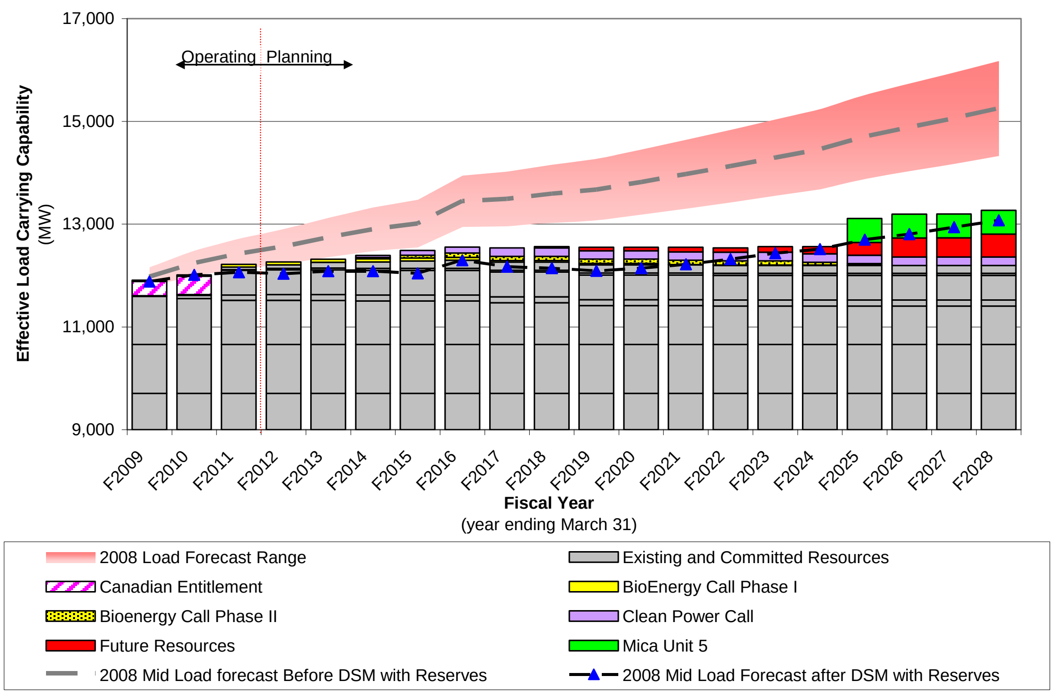


Figure 3 Energy Load / Resource Balance Updated Contingency Resource Plan#1

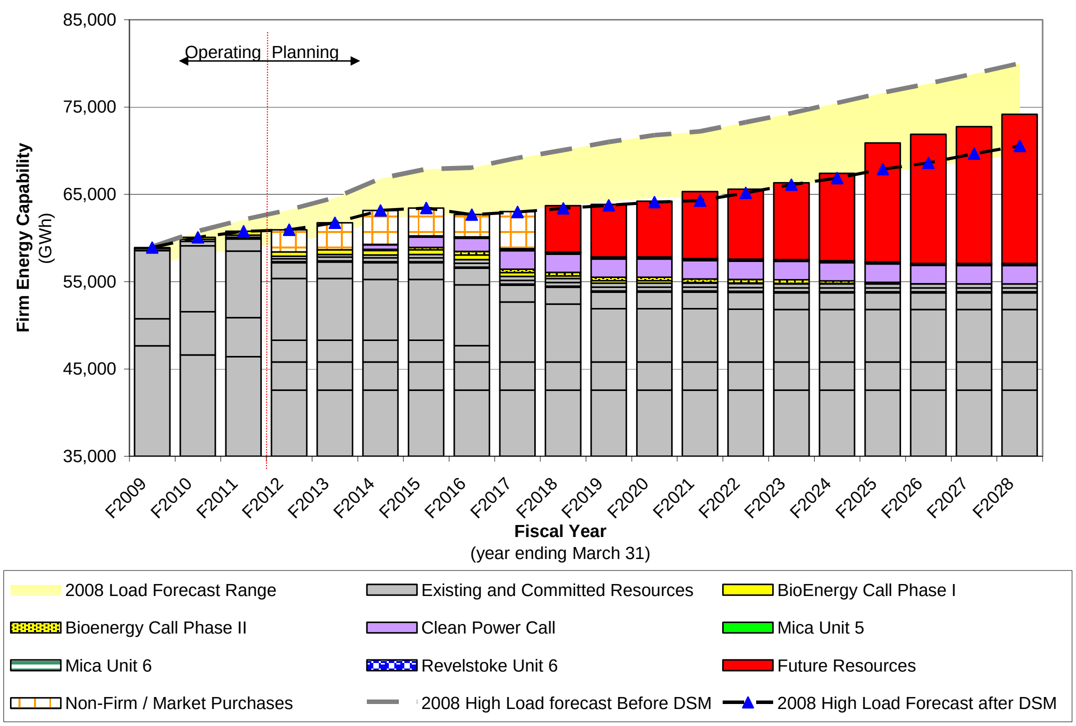


Figure 4 Capacity Load / Resource Balance Updated Contingency Resource Plan #1

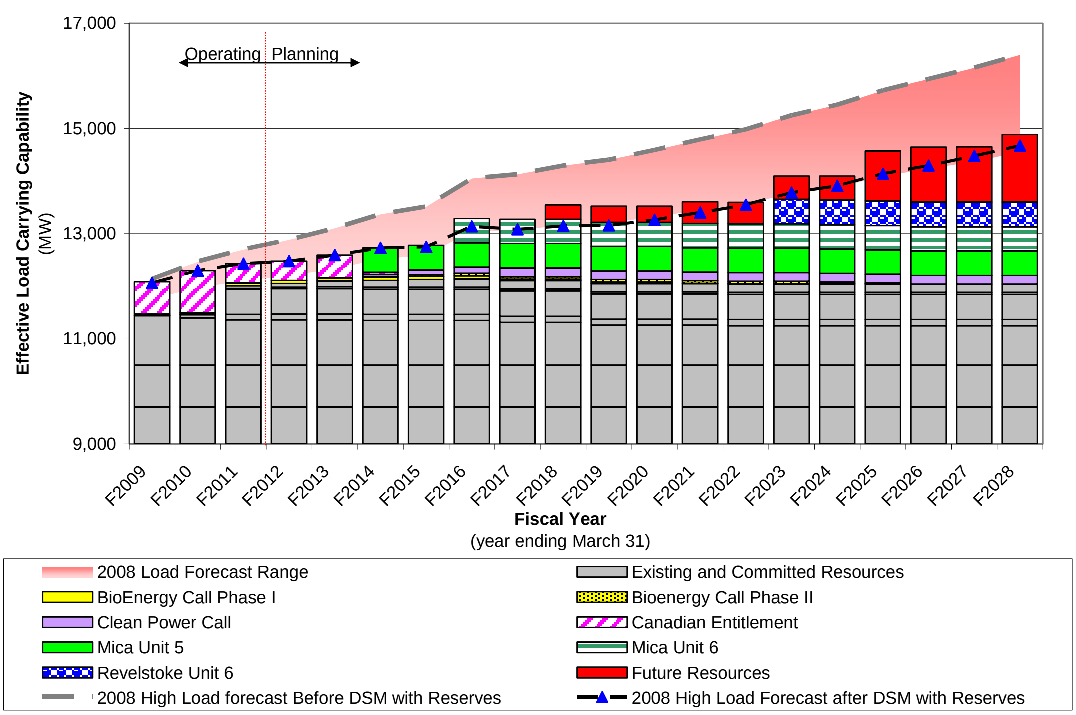


Figure 5 **Energy Load / Resource Balance Updated Contingency Resource Plan #2**

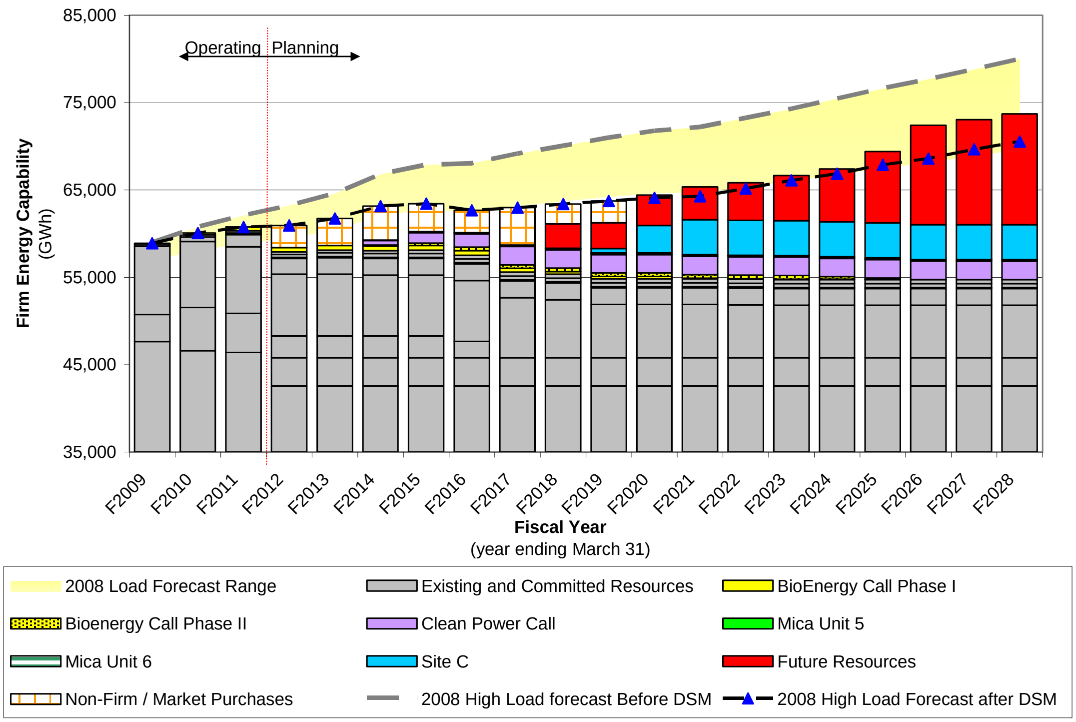


Figure 6 **Capacity Load / Resource Balance Updated Contingency Resource Plan #2**

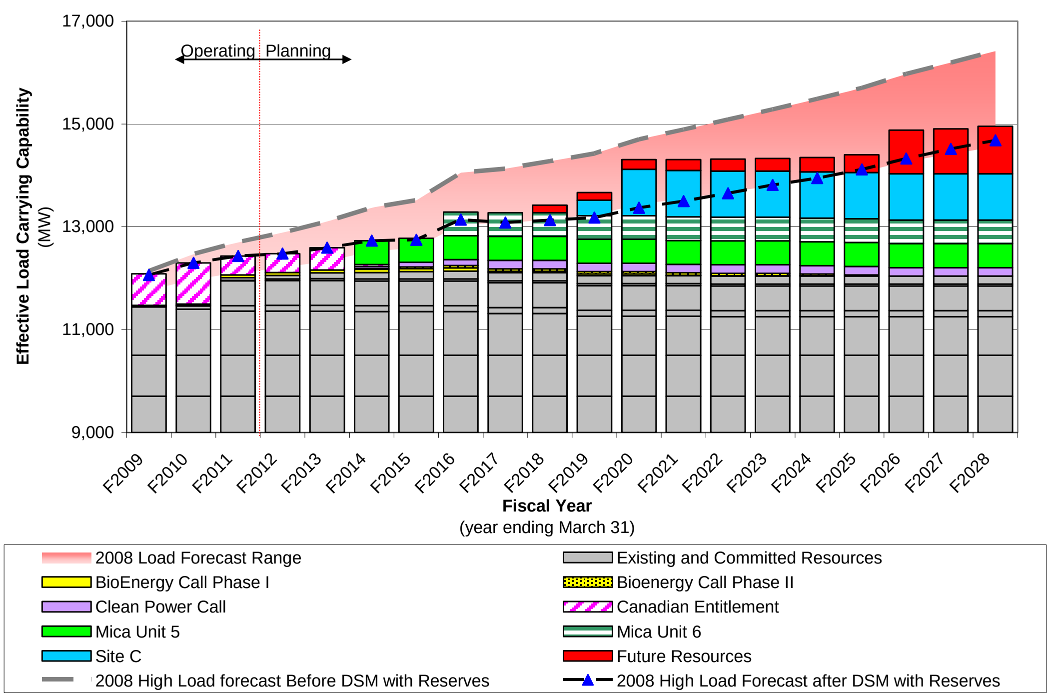


Table 1 Energy Load / Resource Balance Amended Base Resource Plan

Operating ← | → Planning

(GWh)		F2009	F2010	F2011	F2012	F2013	F2014	F2015	F2016	F2017	F2018	F2019	F2020	F2021	F2022	F2023	F2024	F2025	F2026	F2027	F2028
Existing and Committed Supply																					
Heritage Hydroelectric		47,600	46,600	46,400	42,600	42,600	42,600	42,600	42,600	42,600	42,600	42,600	42,600	42,600	42,600	42,600	42,600	42,600	42,600	42,600	42,600
Heritage Thermal / Market Purchases		1,900	3,200	2,300	3,200	3,200	3,200	3,200	3,200	3,200	3,200	3,200	3,200	3,200	3,200	3,200	3,200	3,200	3,200	3,200	3,200
Resource Smart		200	300	300	300	300	300	400	400	500	500	500	500	500	500	500	500	500	500	500	500
Revelstoke Unit 5		0	0	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100
Existing Purchase Contracts (including Alcan 2008 EPA)		7,800	7,600	7,600	7,100	7,100	7,000	7,000	7,000	6,900	6,700	6,100	6,100	6,100	6,100	6,000	6,000	6,000	6,000	6,000	6,000
F2006 Call		0	500	1,400	1,800	1,900	1,900	1,900	1,900	1,900	1,900	1,900	1,900	1,900	1,900	1,900	1,900	1,900	1,900	1,900	1,900
Standing Offer Program		0	0	100	300	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400
Sub-total	**(a)**	57,600	58,100	58,100	55,400	55,600	55,600	55,600	55,700	55,600	55,400	54,800	54,800	54,800	54,800	54,700	54,700	54,700	54,700	54,700	54,700
Proposed New Supply																					
Bioenergy Call - Phase I		100	200	400	500	500	500	500	500	400	300	300	300	100	100	100	100	100	0	0	0
Bioenergy Call - Phase II		0	0	0	0	0	200	500	700	700	700	700	700	700	700	700	500	200	0	0	0
Clean Power Call		0	0	0	0	0	500	1,200	1,500	2,100	2,100	2,100	2,100	2,100	2,100	2,100	2,100	2,100	2,100	2,100	2,100
Mica Unit 5		0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	100	100	100	100
Future Resources		0	0	0	0	0	0	0	0	0	400	1,100	1,100	1,300	1,700	2,800	3,600	5,500	7,500	8,200	9,100
Sub-total	**(b)**	100	200	400	500	500	1,300	2,200	2,700	3,200	3,500	4,200	4,200	4,200	4,600	5,700	6,200	8,000	9,700	10,400	11,300
Additional Non-Firm Energy Supply																					
Non Firm / Market Allowance		0	0	0	2,500	2,500	2,500	2,500	1,900	0	0	0	0	0	0	0	0	0	0	0	0
Sub-total	**(c)**	0	0	0	2,500	2,500	2,500	2,500	1,900	0	0	0	0	0	0	0	0	0	0	0	0
Total Supply	**(d) = a + b + c**	57,700	58,300	58,600	58,400	58,600	59,300	60,300	60,300	58,800	58,900	59,000	59,000	59,000	59,400	60,400	60,900	62,700	64,500	65,200	66,100
Demand - Integrated System Total Gross Requirements																					
2008 High Load Forecast Before DSM	**(e)**	59,000	60,800	62,100	63,200	64,600	66,800	67,900	68,100	69,200	70,100	71,000	71,800	72,200	73,300	74,300	75,500	76,600	77,700	78,800	80,000
2008 Mid Load Forecast Before DSM	**(f)**	58,000	59,400	60,500	61,400	62,500	64,500	65,300	65,300	66,200	66,900	67,600	68,200	68,500	69,300	70,200	71,100	72,100	72,900	73,800	74,800
2008 Low Load Forecast Before DSM	**(g)**	57,000	58,100	58,900	59,500	60,400	62,100	62,700	62,500	63,200	63,700	64,200	64,600	64,700	65,400	66,000	66,800	67,500	68,200	68,900	69,700
Demand Side Management																					
Updated Option A - Mid Range with Loss Savings		300	1,100	1,900	3,000	3,700	4,700	5,600	6,700	7,600	8,300	9,100	9,600	9,900	10,200	10,400	10,800	11,100	11,500	11,600	11,900
	(h)	300	1,100	1,900	3,000	3,700	4,700	5,600	6,700	7,600	8,300	9,100	9,600	9,900	10,200	10,400	10,800	11,100	11,500	11,600	11,900
Load after DSM																					
2008 High Load Forecast after DSM	**(e - h)**	58,700	59,600	60,200	60,200	60,900	62,200	62,300	61,400	61,500	61,800	61,900	62,200	62,300	63,100	64,000	64,600	65,600	66,200	67,200	68,100
2008 Mid Load Forecast after DSM	**(f - h)**	57,700	58,300	58,600	58,400	58,800	59,800	59,700	58,600	58,500	58,600	58,600	58,700	58,600	59,200	59,800	60,300	61,000	61,400	62,200	62,900
2008 Low Load Forecast after DSM	**(g - h)**	56,700	57,000	56,900	56,500	56,700	57,400	57,100	55,800	55,500	55,400	55,200	55,100	54,800	55,200	55,700	55,900	56,400	56,700	57,300	57,800
Surplus / Deficit		**F2009**	**F2010**	**F2011**	**F2012**	**F2013**	**F2014**	**F2015**	**F2016**	**F2017**	**F2018**	**F2019**	**F2020**	**F2021**	**F2022**	**F2023**	**F2024**	**F2025**	**F2026**	**F2027**	**F2028**
2008 High Load Forecast Surplus / Deficit	**(d - e + h)**	0	0	0	-1,800	-2,200	-2,800	-2,000	-1,100	-2,700	-2,900	-2,900	-3,200	-3,300	-3,700	-3,500	-3,700	-2,800	-1,700	-2,000	-2,000
2008 Mid Load Forecast Surplus / Deficit	**(d - f + h)**	0	0	0	0	-200	-500	600	1,700	300	300	500	400	500	200	600	700	1,700	3,000	3,000	3,200
2008 Low Load Forecast Surplus / Deficit	**(d - g + h)**	0	0	0	1,900	1,900	1,900	3,200	4,400	3,300	3,400	3,800	3,900	4,200	4,200	4,800	5,000	6,300	7,800	7,900	8,300

Note: Values are rounded to the nearest 100 GWh

Table 2 Capacity Load / Resource Balance Amended Base Resource Plan

(MW)		F2009	F2010	F2011	F2012	F2013	F2014	F2015	F2016	F2017	F2018	F2019	F2020	F2021	F2022	F2023	F2024	F2025	F2026	F2027	F2028
		Operating			Planning																
Supply Requiring Reserves																					
Existing and Committed Supply																					
Heritage Hydroelectric		9,700	9,700	9,700	9,700	9,700	9,700	9,700	9,700	9,700	9,700	9,700	9,700	9,700	9,700	9,700	9,700	9,700	9,700	9,700	9,700
Heritage Thermal / Market Purchases		950	950	950	950	950	950	950	950	950	950	950	950	950	950	950	950	950	950	950	950
Resource Smart		0	0	50	50	100	150	150	150	150	150	150	150	150	150	150	150	150	150	150	150
Revelstoke Unit 5		0	0	500	500	500	500	500	500	500	500	500	500	500	500	500	500	500	500	500	500
Existing Purchase Contracts (excluding Alcan 2008 EPA)		650	650	650	650	650	650	650	650	650	650	600	600	600	600	600	600	600	600	600	600
F2006 Call		0	50	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100
Standing Offer Program		0	0	0	50	50	50	50	50	50	50	50	50	50	50	50	50	50	50	50	50
Sub-total	(a)	11,300	11,400	11,950	12,000	12,050	12,050	12,100	12,100	12,100	12,100	12,050	12,050	12,050	12,050	12,050	12,050	12,050	12,050	12,050	12,050
Proposed New Supply																					
Bioenergy Call - Phase I		0	0	50	50	50	50	50	50	50	50	50	50	0	0	0	0	0	0	0	0
Bioenergy Call - Phase II		0	0	0	0	0	50	50	100	100	100	100	100	100	100	100	50	50	0	0	0
Clean Power Call		0	0	0	0	0	50	100	100	150	150	150	150	150	150	150	150	150	150	150	150
Mica Unit 5		0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	450	450	450	450
Future Resources		0	0	0	0	0	0	0	0	0	50	50	50	100	100	100	150	250	350	350	450
Sub-total	(b)	0	0	50	50	50	100	200	250	300	300	350	350	350	350	350	350	900	1,000	1,000	1,050
Supply Requiring Reserves	(c) = a + b	11,300	11,400	12,000	12,050	12,100	12,200	12,300	12,350	12,400	12,400	12,400	12,400	12,400	12,400	12,400	12,400	12,950	13,050	13,050	13,100
Reserves (see footnote)																					
14% of Supply Requiring Reserves	(d) = 14% * c	1,600	1,600	1,700	1,700	1,700	1,700	1,700	1,750	1,750	1,750	1,750	1,750	1,750	1,750	1,750	1,750	1,800	1,800	1,800	1,850
Minus: 400 MW market reliance	(e)	-400	-400	-400	-400	-400	-400	-400	0	0	0	0	0	0	0	0	0	0	0	0	0
Net Reserves	(f) = d + e	1,200	1,200	1,300	1,300	1,300	1,300	1,300	1,750	1,750	1,750	1,750	1,750	1,750	1,750	1,750	1,750	1,800	1,800	1,800	1,850
Supply Not Requiring Reserves																					
Existing and Committed Supply																					
Alcan 2008 EPA		300	250	200	200	200	200	200	200	150	150	150	150	150	150	150	150	150	150	150	150
Sub-total	(g)	300	250	200	200	200	200	200	200	150	150	150	150	150	150	150	150	150	150	150	150
Supply Not Requiring Reserves	(g)	300	250	200	200	200	200	200	200	150	150	150	150	150	150	150	150	150	150	150	150
Effective Load Carrying Capability																					
Supply Requiring Reserves - Reserves + Supply Not Requiring Reserves	(h) = c - f + g	10,400	10,450	10,950	11,000	11,000	11,100	11,150	10,800	10,800	10,850	10,800	10,800	10,800	10,800	10,850	10,850	11,300	11,350	11,350	11,450
Demand - Integrated System Total Gross Requirements																					
2008 High Load Forecast Before DSM	(i)	11,000	11,300	11,450	11,600	11,850	12,000	12,150	12,200	12,300	12,400	12,550	12,700	12,900	13,100	13,300	13,500	13,700	13,900	14,150	14,350
2008 Mid Load Forecast Before DSM	(j)	10,800	11,050	11,150	11,300	11,450	11,600	11,700	11,700	11,750	11,850	11,950	12,100	12,250	12,400	12,550	12,700	12,900	13,050	13,250	13,400
2008 Low Load Forecast Before DSM	(k)	10,600	10,800	10,850	10,950	11,050	11,150	11,250	11,200	11,250	11,300	11,350	11,450	11,550	11,700	11,800	11,950	12,050	12,200	12,350	12,500
Demand Side Management																					
Updated Option A - Mid Range with Loss Savings		100	250	350	550	650	800	950	1,150	1,300	1,450	1,600	1,700	1,750	1,800	1,850	1,950	2,000	2,100	2,100	2,200
Sub-total	(l)	100	250	350	550	650	800	950	1,150	1,300	1,450	1,600	1,700	1,750	1,800	1,850	1,950	2,000	2,100	2,100	2,200
Load after DSM																					
2008 High Load Forecast after DSM	(i - l)	10,900	11,050	11,100	11,100	11,150	11,200	11,200	11,050	10,950	10,950	10,950	11,050	11,150	11,300	11,450	11,550	11,700	11,850	12,000	12,150
2008 Mid Load Forecast after DSM	(j - l)	10,700	10,800	10,800	10,750	10,800	10,800	10,700	10,550	10,450	10,400	10,350	10,400	10,500	10,600	10,700	10,800	10,900	11,000	11,100	11,250
2008 Low Load Forecast after DSM	(k - l)	10,500	10,550	10,500	10,400	10,400	10,350	10,250	10,050	9,900	9,850	9,750	9,800	9,800	9,900	9,950	10,000	10,050	10,150	10,250	10,300
Effective Load Carrying Capability Surplus / Deficit		**F2009**	**F2010**	**F2011**	**F2012**	**F2013**	**F2014**	**F2015**	**F2016**	**F2017**	**F2018**	**F2019**	**F2020**	**F2021**	**F2022**	**F2023**	**F2024**	**F2025**	**F2026**	**F2027**	**F2028**
2008 High Load Forecast Surplus / Deficit	**(h - i + l)**	**-450**	**-600**	**-150**	**-100**	**-150**	**-100**	**0**	**-250**	**-150**	**-150**	**-150**	**-250**	**-350**	**-500**	**-600**	**-750**	**-400**	**-450**	**-650**	**-750**
2008 Mid Load Forecast Surplus / Deficit	**m = (h - j + l)**	**-300**	**-350**	**150**	**250**	**250**	**300**	**450**	**250**	**350**	**400**	**450**	**400**	**350**	**200**	**150**	**50**	**400**	**400**	**250**	**200**
2008 Low Load Forecast Surplus / Deficit	**(h - k + l)**	**-100**	**-100**	**450**	**550**	**600**	**750**	**900**	**750**	**900**	**1,000**	**1,050**	**1,050**	**1,000**	**950**	**850**	**850**	**1,250**	**1,250**	**1,150**	**1,100**
Additional Supply Potential																					
Canadian Entitlement	(n)	300	350	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Surplus / Deficit with Canadian Entitlement	**(m + n)**	**0**	**0**	**150**	**250**	**250**	**300**	**450**	**250**	**350**	**400**	**450**	**400**	**350**	**200**	**150**	**50**	**400**	**400**	**250**	**200**

Reserve Footnote

BC Hydro's reserves are based on 14% of total supply excluding the 400 MW market reliance prior to F2016 and the Alcan 2008 EPA.

Note: values are rounded to the nearest 50 MW.

Table 3 Energy Load / Resource Balance Updated Contingency Resource Plan #1

Operating ← | → Planning

(GWh)			F2009	F2010	F2011	F2012	F2013	F2014	F2015	F2016	F2017	F2018	F2019	F2020	F2021	F2022	F2023	F2024	F2025	F2026	F2027	F2028
Existing and Committed Supply																						
Heritage Hydroelectric			47,600	46,600	46,400	42,600	42,600	42,600	42,600	42,600	42,600	42,600	42,600	42,600	42,600	42,600	42,600	42,600	42,600	42,600	42,600	42,600
Heritage Thermal / Market Purchases			3,100	4,900	4,500	3,200	3,200	3,200	3,200	3,200	3,200	3,200	3,200	3,200	3,200	3,200	3,200	3,200	3,200	3,200	3,200	3,200
Resource Smart			200	300	300	300	300	300	400	400	500	500	500	500	500	500	500	500	500	500	500	500
Revelstoke Unit 5			0	0	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100
Existing Purchase Contracts (including Alcan 2008 EPA)			7,800	7,600	7,600	7,100	7,100	7,000	7,000	7,000	6,900	6,700	6,100	6,100	6,100	6,100	6,000	6,000	6,000	6,000	6,000	6,000
F2006 Call			0	500	1,400	1,800	1,900	1,900	1,900	1,900	1,900	1,900	1,900	1,900	1,900	1,900	1,900	1,900	1,900	1,900	1,900	1,900
Standing Offer Program			0	0	100	300	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400
	Sub-total	**(a)**	58,800	59,900	60,300	55,400	55,600	55,600	55,600	55,700	55,600	55,400	54,800	54,800	54,800	54,800	54,700	54,700	54,700	54,700	54,700	54,700
Proposed New Supply																						
Bioenergy Call - Phase I			100	200	400	500	500	500	500	500	400	300	300	300	100	100	100	100	100	0	0	0
Bioenergy Call - Phase II			0	0	0	0	0	100	300	400	400	400	400	400	400	400	400	300	100	0	0	0
Clean Power Call			0	0	0	0	0	500	1,200	1,500	2,100	2,100	2,100	2,100	2,100	2,100	2,100	2,100	2,100	2,100	2,100	2,100
Mica Unit 5			0	0	0	0	0	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100
Mica Unit 6			0	0	0	0	0	0	0	0	100	100	100	100	100	100	100	100	100	100	100	100
Revelstoke 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	0	0	5,300	6,000	6,400	7,700	8,000	8,800	10,000	13,600	14,800	15,700	17,100
	Sub-total	**(b)**	100	200	400	500	500	1,200	2,100	2,600	3,100	8,300	9,000	9,300	10,400	10,800	11,500	12,600	16,100	17,100	18,000	19,400
Additional Non-Firm Energy Supply																						
Non Firm / Market Allowance			0	0	0	2,500	2,500	2,500	2,500	1,900	0	0	0	0	0	0	0	0	0	0	0	0
	Sub-total	**(c)**	0	0	0	2,500	2,500	2,500	2,500	1,900	0	0	0	0	0	0	0	0	0	0	0	0
Total Supply		**(d) = a + b + c**	58,900	60,100	60,800	58,400	58,600	59,300	60,200	60,100	58,700	63,600	63,800	64,200	65,300	65,500	66,300	67,400	70,900	71,900	72,700	74,200
Demand - Integrated System Total Gross Requirements																						
2008 High Load Forecast Before DSM		**(e)**	59,000	60,800	62,100	63,200	64,600	66,800	67,900	68,100	69,200	70,100	71,000	71,800	72,200	73,300	74,300	75,500	76,600	77,700	78,800	80,000
Demand Side Management																						
Option A - Low Range with Loss Savings			100	700	1,300	2,300	2,900	3,700	4,500	5,400	6,200	6,700	7,300	7,700	8,000	8,100	8,200	8,600	8,800	9,100	9,200	9,400
	Sub-total	**(f)**	100	700	1,300	2,300	2,900	3,700	4,500	5,400	6,200	6,700	7,300	7,700	8,000	8,100	8,200	8,600	8,800	9,100	9,200	9,400
Load after DSM																						
2008 High Load Forecast after DSM		**(e - f)**	58,900	60,100	60,800	60,900	61,700	63,100	63,400	62,700	63,000	63,400	63,700	64,100	64,300	65,200	66,100	66,900	67,900	68,600	69,700	70,600
Surplus / Deficit			**F2009**	**F2010**	**F2011**	**F2012**	**F2013**	**F2014**	**F2015**	**F2016**	**F2017**	**F2018**	**F2019**	**F2020**	**F2021**	**F2022**	**F2023**	**F2024**	**F2025**	**F2026**	**F2027**	**F2028**
2008 High Load Forecast Surplus / Deficit		**(d - e + f)**	0	0	0	-2,500	-3,100	-3,900	-3,200	-2,600	-4,300	300	100	100	1,000	400	200	500	3,000	3,300	3,100	3,600

Note: Values are rounded to the nearest 100 GWh

Table 4 Capacity Load / Resource Balance Updated Contingency Resource Plan #1

Operating ← | → Planning

(MW)		F2009	F2010	F2011	F2012	F2013	F2014	F2015	F2016	F2017	F2018	F2019	F2020	F2021	F2022	F2023	F2024	F2025	F2026	F2027	F2028
Supply Requiring Reserves																					
Existing and Committed Supply																					
Heritage Hydroelectric		9,700	9,700	9,700	9,700	9,700	9,700	9,700	9,700	9,700	9,700	9,700	9,700	9,700	9,700	9,700	9,700	9,700	9,700	9,700	9,700
Heritage Thermal / Market Purchases		800	800	800	800	800	800	800	800	800	800	800	800	800	800	800	800	800	800	800	800
Resource Smart		0	0	50	50	100	150	150	150	150	150	150	150	150	150	150	150	150	150	150	150
Revelstoke Unit 5		0	0	500	500	500	500	500	500	500	500	500	500	500	500	500	500	500	500	500	500
Existing Purchase Contracts (excluding Alcan 2008 EPA)		650	650	650	650	650	650	650	650	650	650	600	600	600	600	600	600	600	600	600	600
F2006 Call		0	50	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100
Standing Offer Program		0	0	0	50	50	50	50	50	50	50	50	50	50	50	50	50	50	50	50	50
Sub-total	(a)	11,150	11,250	11,800	11,850	11,900	11,900	11,950	11,950	11,950	11,950	11,900	11,900	11,900	11,900	11,900	11,900	11,900	11,900	11,900	11,900
Proposed New Supply																					
Bioenergy Call - Phase I		0	0	50	50	50	50	50	50	50	50	50	50	0	0	0	0	0	0	0	0
Bioenergy Call - Phase II		0	0	0	0	0	0	50	50	50	50	50	50	50	50	50	50	0	0	0	0
Clean Power Call		0	0	0	0	0	50	100	100	150	150	150	150	150	150	150	150	150	150	150	150
Mica Unit 5		0	0	0	0	0	450	450	450	450	450	450	450	450	450	450	450	450	450	450	450
Mica Unit 6		0	0	0	0	0	0	0	450	450	450	450	450	450	450	450	450	450	450	450	450
Revelstoke Unit 6		0	0	0	0	0	0	0	0	0	0	0	0	0	0	450	450	450	450	450	450
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	0	0	300	300	300	400	400	450	450	950	1,050	1,050	1,300
Sub-total	(b)	0	0	50	50	50	600	650	1,150	1,150	1,450	1,450	1,450	1,550	1,550	2,050	2,050	2,550	2,600	2,600	2,850
Supply Requiring Reserves	(c) = a + b	11,150	11,250	11,850	11,900	11,950	12,500	12,600	13,100	13,100	13,400	13,350	13,350	13,450	13,450	13,950	13,950	14,450	14,500	14,500	14,750
Reserves (see footnote)																					
14% of Supply Requiring Reserves	(d) = 14% * c	1,550	1,600	1,650	1,650	1,650	1,750	1,750	1,850	1,850	1,850	1,850	1,850	1,900	1,900	1,950	1,950	2,000	2,050	2,050	2,050
Minus: 400 MW market reliance	(e)	-400	-400	-400	-400	-400	-400	-400													
Net Reserves	(f) = d + e	1,150	1,200	1,250	1,250	1,250	1,350	1,350	1,850	1,850	1,850	1,850	1,850	1,900	1,900	1,950	1,950	2,000	2,050	2,050	2,050
Supply Not Requiring Reserves																					
Existing and Committed Supply																					
Alcan 2008 EPA		300	250	200	200	200	200	200	200	150	150	150	150	150	150	150	150	150	150	150	150
Sub-total	(g)	300	250	200	200	200	200	200	200	150	150	150	150	150	150	150	150	150	150	150	150
Supply Not Requiring Reserves	(g)	300	250	200	200	200	200	200	200	150	150	150	150	150	150	150	150	150	150	150	150
Effective Load Carrying Capability																					
Supply Requiring Reserves - Reserves + Supply Not Requiring Reserves	(h) = c - f + g	10,300	10,300	10,800	10,850	10,900	11,350	11,400	11,450	11,450	11,650	11,650	11,650	11,750	11,700	12,150	12,150	12,550	12,600	12,600	12,850
Demand - Integrated System Total Gross Requirements																					
2008 High Load Forecast Before DSM	(i)	11,000	11,300	11,450	11,600	11,850	12,000	12,150	12,200	12,300	12,400	12,550	12,700	12,900	13,100	13,300	13,500	13,700	13,900	14,150	14,350
Demand Side Management																					
Updated Option A - Low Range with Loss Savings		100	150	250	400	500	650	750	900	1,050	1,150	1,250	1,350	1,400	1,450	1,450	1,550	1,600	1,650	1,700	1,750
Sub-total	(j)	100	150	250	400	500	650	750	900	1,050	1,150	1,250	1,350	1,400	1,450	1,450	1,550	1,600	1,650	1,700	1,750
Load after DSM																					
2008 High Load Forecast after DSM	(i - j)	10,900	11,100	11,150	11,200	11,300	11,400	11,400	11,300	11,250	11,250	11,300	11,400	11,500	11,650	11,850	11,950	12,100	12,250	12,450	12,600
Effective Load Carrying Capability Surplus / Deficit		**F2009**	**F2010**	**F2011**	**F2012**	**F2013**	**F2014**	**F2015**	**F2016**	**F2017**	**F2018**	**F2019**	**F2020**	**F2021**	**F2022**	**F2023**	**F2024**	**F2025**	**F2026**	**F2027**	**F2028**
2008 High Load Forecast Surplus / Deficit	k = (h - i + j)	**-600**	**-800**	**-350**	**-350**	**-450**	**-50**	**50**	**150**	**200**	**400**	**350**	**250**	**200**	**50**	**300**	**200**	**450**	**350**	**150**	**200**
Additional Supply Potential																					
Canadian Entitlement	(l)	600	800	350	350	450	50	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Surplus / Deficit with Canadian Entitlement	(k + l)	0	**0**	**0**	**0**	**0**	**0**	**50**	**150**	**200**	**400**	**350**	**250**	**200**	**50**	**300**	**200**	**450**	**350**	**150**	**200**

Reserve Footnote

BC Hydro's reserves are based on 14% of total supply excluding the 400 MW market reliance prior to F2016 and the Alcan 2008 EPA.

Note: values are rounded to the nearest 50 MW.

Table 5 Energy Load / Resource Balance Updated Contingency Resource Plan #2

Operating | Planning

(GWh)		F2009	F2010	F2011	F2012	F2013	F2014	F2015	F2016	F2017	F2018	F2019	F2020	F2021	F2022	F2023	F2024	F2025	F2026	F2027	F2028
Existing and Committed Supply																					
Heritage Hydroelectric		47,600	46,600	46,400	42,600	42,600	42,600	42,600	42,600	42,600	42,600	42,600	42,600	42,600	42,600	42,600	42,600	42,600	42,600	42,600	42,600
Heritage Thermal / Market Purchases		3,100	4,900	4,500	3,200	3,200	3,200	3,200	3,200	3,200	3,200	3,200	3,200	3,200	3,200	3,200	3,200	3,200	3,200	3,200	3,200
Resource Smart		200	300	300	300	300	300	400	400	500	500	500	500	500	500	500	500	500	500	500	500
Revelstoke Unit 5		0	0	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100
Existing Purchase Contracts (including Alcan 2008 EPA)		7,800	7,600	7,600	7,100	7,100	7,000	7,000	7,000	6,900	6,700	6,100	6,100	6,100	6,100	6,000	6,000	6,000	6,000	6,000	6,000
F2006 Call		0	500	1,400	1,800	1,900	1,900	1,900	1,900	1,900	1,900	1,900	1,900	1,900	1,900	1,900	1,900	1,900	1,900	1,900	1,900
Standing Offer Program		0	0	100	300	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400
Sub-total	**(a)**	58,800	59,900	60,300	55,400	55,600	55,600	55,600	55,700	55,600	55,400	54,800	54,800	54,800	54,800	54,700	54,700	54,700	54,700	54,700	54,700
Proposed New Supply																					
Bioenergy Call - Phase I		100	200	400	500	500	500	500	500	400	300	300	300	100	100	100	100	100	0	0	0
Bioenergy Call - Phase II		0	0	0	0	0	100	300	400	400	400	400	400	400	400	400	300	100	0	0	0
Clean Power Call		0	0	0	0	0	500	1,200	1,500	2,100	2,100	2,100	2,100	2,100	2,100	2,100	2,100	2,100	2,100	2,100	2,100
Mica Unit 5		0	0	0	0	0	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100
Mica Unit 6		0	0	0	0	0	0	0	0	100	100	100	100	100	100	100	100	100	100	100	100
Revelstoke 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	500	3,200	4,000	4,000	4,000	4,000	4,000	4,000	4,000	4,000
Future Resources		0	0	0	0	0	0	0	0	0	2,800	3,000	3,500	3,700	4,300	5,200	6,000	8,200	11,400	12,000	12,700
Sub-total	**(b)**	100	200	400	500	500	1,200	2,100	2,600	3,100	5,700	6,400	9,600	10,500	11,000	11,900	12,700	14,700	17,700	18,300	19,000
Additional Non-Firm Energy Supply																					
Non Firm / Market Allowance		0	0	0	2,500	2,500	2,500	2,500	1,900	0	0	0	0	0	0	0	0	0	0	0	0
Sub-total	**(c)**	0	0	0	2,500	2,500	2,500	2,500	1,900	0	0	0	0	0	0	0	0	0	0	0	0
Total Supply	**(d) = a + b + c**	58,900	60,100	60,800	58,400	58,600	59,300	60,200	60,100	58,700	61,100	61,200	64,400	65,300	65,800	66,600	67,400	69,400	72,400	73,100	73,700
Demand - Integrated System Total Gross Requirements																					
2008 High Load Forecast Before DSM	**(e)**	59,000	60,800	62,100	63,200	64,600	66,800	67,900	68,100	69,200	70,100	71,000	71,800	72,200	73,300	74,300	75,500	76,600	77,700	78,800	80,000
Demand Side Management																					
Option A - Low Range with Loss Savings		100	700	1,300	2,300	2,900	3,700	4,500	5,400	6,200	6,700	7,300	7,700	8,000	8,100	8,200	8,600	8,800	9,100	9,200	9,400
Sub-total	**(f)**	100	700	1,300	2,300	2,900	3,700	4,500	5,400	6,200	6,700	7,300	7,700	8,000	8,100	8,200	8,600	8,800	9,100	9,200	9,400
Load after DSM																					
2008 High Load Forecast after DSM	**(e - f)**	58,900	60,100	60,800	60,900	61,700	63,100	63,400	62,700	63,000	63,400	63,700	64,100	64,300	65,200	66,100	66,900	67,900	68,600	69,700	70,600
Surplus / Deficit																					
		F2009	F2010	F2011	F2012	F2013	F2014	F2015	F2016	F2017	F2018	F2019	F2020	F2021	F2022	F2023	F2024	F2025	F2026	F2027	F2028
2008 High Load Forecast Surplus / Deficit	**(d - e + f)**	0	0	0	-2,500	-3,100	-3,900	-3,200	-2,600	-4,300	-2,300	-2,500	300	1,100	700	500	500	1,500	3,800	3,400	3,200

Note: Values are rounded to the nearest 100 GWh

Table 6 Capacity Load / Resource Balance Updated Contingency Resource Plan #2

Operating | Planning

(MW)		F2009	F2010	F2011	F2012	F2013	F2014	F2015	F2016	F2017	F2018	F2019	F2020	F2021	F2022	F2023	F2024	F2025	F2026	F2027	F2028
Supply Requiring Reserves																					
Existing and Committed Supply																					
Heritage Hydroelectric		9,700	9,700	9,700	9,700	9,700	9,700	9,700	9,700	9,700	9,700	9,700	9,700	9,700	9,700	9,700	9,700	9,700	9,700	9,700	9,700
Heritage Thermal / Market Purchases		800	800	800	800	800	800	800	800	800	800	800	800	800	800	800	800	800	800	800	800
Resource Smart		0	0	50	50	100	150	150	150	150	150	150	150	150	150	150	150	150	150	150	150
Revelstoke Unit 5		0	0	500	500	500	500	500	500	500	500	500	500	500	500	500	500	500	500	500	500
Existing Purchase Contracts (excluding Alcan 2008 EPA)		650	650	650	650	650	650	650	650	650	650	600	600	600	600	600	600	600	600	600	600
F2006 Call		0	50	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100
Standing Offer Program		0	0	0	50	50	50	50	50	50	50	50	50	50	50	50	50	50	50	50	50
Sub-total	**(a)**	11,150	11,250	11,800	11,850	11,900	11,900	11,950	11,950	11,950	11,950	11,900	11,900	11,900	11,900	11,900	11,900	11,900	11,900	11,900	11,900
Proposed New Supply																					
Bioenergy Call - Phase I		0	0	50	50	50	50	50	50	50	50	50	50	0	0	0	0	0	0	0	0
Bioenergy Call - Phase II		0	0	0	0	0	0	50	50	50	50	50	50	50	50	50	50	0	0	0	0
Clean Power Call		0	0	0	0	0	50	100	100	150	150	150	150	150	150	150	150	150	150	150	150
Mica Unit 5		0	0	0	0	0	450	450	450	450	450	450	450	450	450	450	450	450	450	450	450
Mica Unit 6		0	0	0	0	0	0	0	450	450	450	450	450	450	450	450	450	450	450	450	450
Revelstoke 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	300	900	900	900	900	900	900	900	900	900
Future Resources		0	0	0	0	0	0	0	0	0	150	150	200	200	250	250	300	350	850	850	950
Sub-total	**(b)**	0	0	50	50	50	600	650	1,150	1,150	1,300	1,600	2,250	2,250	2,300	2,300	2,300	2,350	2,850	2,850	2,900
Supply Requiring Reserves	**(c) = a + b**	11,150	11,250	11,850	11,900	11,950	12,500	12,600	13,100	13,100	13,250	13,500	14,150	14,150	14,200	14,200	14,200	14,250	14,750	14,750	14,800
Reserves (see footnote)																					
14% of Supply Requiring Reserves	**(d) = 14% * c**	1,550	1,600	1,650	1,650	1,650	1,750	1,750	1,850	1,850	1,850	1,900	2,000	2,000	2,000	2,000	2,000	2,000	2,050	2,050	2,050
Minus: 400 MW market reliance	**(e)**	-400	-400	-400	-400	-400	-400	-400													
Net Reserves	**(f) = d + e**	1,150	1,200	1,250	1,250	1,250	1,350	1,350	1,850	1,850	1,850	1,900	2,000	2,000	2,000	2,000	2,000	2,000	2,050	2,050	2,050
Supply Not Requiring Reserves																					
Existing and Committed Supply																					
Alcan 2008 EPA		300	250	200	200	200	200	200	200	150	150	150	150	150	150	150	150	150	150	150	150
Sub-total	**(g)**	300	250	200	200	200	200	200	200	150	150	150	150	150	150	150	150	150	150	150	150
Supply Not Requiring Reserves	**(g)**	300	250	200	200	200	200	200	200	150	150	150	150	150	150	150	150	150	150	150	150
Effective Load Carrying Capability																					
Supply Requiring Reserves - Reserves + Supply Not Requiring Reserves	**(h) = c - f + g**	10,300	10,300	10,800	10,850	10,900	11,350	11,400	11,450	11,450	11,550	11,800	12,350	12,350	12,350	12,350	12,350	12,400	12,800	12,850	12,900
Demand - Integrated System Total Gross Requirements																					
2008 High Load Forecast Before DSM	**(i)**	11,000	11,300	11,450	11,600	11,850	12,000	12,150	12,200	12,300	12,400	12,550	12,700	12,900	13,100	13,300	13,500	13,700	13,900	14,150	14,350
Demand Side Management																					
Updated Option A - Low Range with Loss Savings		100	150	250	400	500	650	750	900	1,050	1,150	1,250	1,350	1,400	1,450	1,450	1,550	1,600	1,650	1,700	1,750
Sub-total	**(j)**	100	150	250	400	500	650	750	900	1,050	1,150	1,250	1,350	1,400	1,450	1,450	1,550	1,600	1,650	1,700	1,750
Load after DSM																					
2008 High Load Forecast after DSM	**(i - j)**	10,900	11,100	11,150	11,200	11,300	11,400	11,400	11,300	11,250	11,250	11,300	11,400	11,500	11,650	11,850	11,950	12,100	12,250	12,450	12,600
Effective Load Carrying Capability Surplus / Deficit		**F2009**	**F2010**	**F2011**	**F2012**	**F2013**	**F2014**	**F2015**	**F2016**	**F2017**	**F2018**	**F2019**	**F2020**	**F2021**	**F2022**	**F2023**	**F2024**	**F2025**	**F2026**	**F2027**	**F2028**
2008 High Load Forecast Surplus / Deficit	**k = (h - i + j)**	**-600**	**-800**	**-350**	**-350**	**-450**	**-50**	**50**	**150**	**200**	**300**	**500**	**950**	**800**	**650**	**500**	**400**	**300**	**550**	**400**	**250**
Additional Supply Potential																					
Canadian Entitlement	**(l)**	600	800	350	350	450	50	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Surplus / Deficit with Canadian Entitlement	**(k + l)**	0	**0**	**0**	**0**	**0**	**0**	**50**	**150**	**200**	**300**	**500**	**950**	**800**	**650**	**500**	**400**	**300**	**550**	**400**	**250**

Reserve Footnote

BC Hydro's reserves are based on 14% of total supply excluding the 400 MW market reliance prior to F2016 and the Alcan 2008 EPA.

Note: values are rounded to the nearest 50 MW.