



**BRITISH COLUMBIA
UTILITIES COMMISSION**

**ORDER
NUMBER** G-75-09

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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")
for the Approval of the 2008 Long-Term Acquisition Plan ("2008 LTAP")
Expenditure Request for Fort Nelson Generating Station Upgrade Project

BEFORE: A.J. Pullman, Panel Chair
M.R. Harle, Commissioner
R.J. Milbourne, Commissioner

June 15, 2009

O R D E R

WHEREAS:

- A. On June 12, 2008 BC Hydro filed, pursuant to s. 44.1(2), 44.1(4) and 44.2(1) of the *Utilities Commission Act* ("UCA", the "Act"), the 2008 LTAP with the British Columbia Utilities Commission ("BCUC", the "Commission") for review; and
- B. The 2008 LTAP (Exhibit B-1) is a ten-year plan for acquiring demand-side and supply-side resources to meet demand in British Columbia. The 2008 LTAP both updates and expands the 2006 Integrated Electricity Plan/LTAP, which was the subject of Order G-20-07 ("2006 IEP/LTAP Decision"); and
- C. The 2008 LTAP reflects BC Hydro's commitment to examine the effects of the British Columbia Government's updated energy policy, "The BC Energy Plan: A Vision for Clean Energy Leadership", and the relevant issues in the 2006 IEP/LTAP Decision; and
- D. BC Hydro seeks an Order which, pursuant to s. 44.1(6)(a) of the Act, states that the 2008 LTAP is in the public interest and, pursuant to s. 44.2(3)(a) of the Act, determines that expenditures related to the programs and projects listed in Section 1.1.2 of the Application are in the public interest; and
- E. By letter dated October 24, 2008, BC Hydro filed an update of the evidentiary record related to Fort Nelson which included an amendment of the Order sought with respect to the Fort Nelson Generating Upgrade Project, and revised versions of Appendices N1 and N2 to reflect the updated project cost estimates and to address the issues raised by the Fort Nelson-related Information Requests (Exhibit B-1-10); and
- F. Specifically, BC Hydro seeks an Order that expenditures of \$140.1 million in F2009 to F2012 to complete the definition phase work for, and implement, the Fort Nelson Generating Upgrade Project Case 3.2 ("FNU3") are in the public interest; and

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- G. A Second Procedural Conference was set as a result of a proposed amendment of the Hearing schedule by BC Hydro's letter to the Commission dated November 14, 2008 (Exhibit B-5). In a follow-up letter from BC Hydro dated November 19, 2008 (Exhibit B-6), BC Hydro requested that the Commission issue early orders with respect to the Mica Units 5 and 6 definition phase expenditure request and with respect to the Fort Nelson Generating Station Upgrade Project definition and implementation phase expenditures request; and
- H. At the Second Procedural Conference on November 28, 2008, all Parties spoke to, among other things, the possibility of moving the Fort Nelson Generating Station Upgrade Project to a separate hearing, a separate Argument phase for Mica Units 5 and 6 and separate orders and decisions for these two matters; and
- I. Commission Order G-178-08 dated November 28, 2008 (Exhibit A-12) amended the regulatory timetable and established that the Oral Public Hearing would commence on February 19, 2009. The Order also established that the Mica Units 5 and 6 definition phase expenditure request would be dealt with as part of the main 2008 LTAP argument phase and the Fort Nelson Generating Station Upgrade Project definition and implementation phase expenditures request would remain part of the 2008 LTAP evidentiary and argument phases; and
- J. The Oral Hearing commenced on February 19, 2009 and ended on March 12, 2009. BC Hydro filed its Argument on April 9, 2009; Intervenors filed their Arguments on April 27, 2009; and BC Hydro filed its Reply on May 13, 2009. In Reply, BC Hydro submitted that the FNU3 expenditure request is supported by the Joint Industry Electricity Steering Committee ("JIESC"), Commercial Energy Consumers of British Columbia ("CECBC") and the Independent Power Producers of British Columbia ("IPPBC") and that no Intervenor opposed this expenditure request; and
- K. By letter dated May 25, 2009 (Exhibit A-20), wherein the Commission notified all Parties that the Oral Phase of Argument, provisionally scheduled on June 1, 2009, was required, all Parties were asked to advise the Commission if they would be prepared to make submissions on, among other things, whether the Commission should set conditions on its approval of FNU3 and establish reporting requirements on its implementation, and what such conditions and reporting requirements might include should the Commission approve BC Hydro's request for expenditure; and
- L. At the Oral Phase of Argument, BC Hydro submitted that it accepts the Commission may set conditions as well as reporting requirements. Only three Intervenors addressed this matter: IPPBC, CECBC and Vanport Sterilizers and all accepted either explicitly or implicitly that the Commission may set conditions; and
- M. The Commission Panel has considered the evidence on the \$140.1 million expenditures requested to complete the definition phase work for, and implement, FNU3 and the submissions by BC Hydro and Intervenors all as set forth in the Decision issued concurrently with and attached as Appendix A to this Order.

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NOW THEREFORE the Commission determines, for the Reasons stated in the Decision, that:

1. Subject to filing with the Commission a copy of the resolution of BC Hydro's Board of Directors approving FNU3, the \$140.1 million expenditures to complete the definition phase and implementation phase of FNU3 are in the public interest under s. 44.2(3)(a) of the Act.
2. BC Hydro is directed to file with the Commission quarterly project reports and a final report within six months of project completion, in a format to be agreed by Commission staff and BC Hydro.

DATED at the City of Vancouver, in the Province of British Columbia, this 15th day of June 2009.

BY ORDER

Original signed by:

Anthony J. Pullman
Panel Chair

Attachment

An Application by British Columbia Hydro and Power Authority ("BC Hydro")
for the Approval of the 2008 Long-Term Acquisition Plan ("2008 LTAP")
Expenditure Request for Fort Nelson Generating Station Upgrade Project

REASONS FOR DECISION

EXECUTIVE SUMMARY

These Reasons for Decision address BC Hydro's request for a determination prior to the issuing of the Commission's Decision on BC Hydro's 2008 Long-Term Acquisition Plan that expenditures of \$140.1 million in F2009 – F2012 required to complete the definition phase work for, and implement, Fort Nelson Generating Station Upgrade Project Case 3.2 ("FNU3") are in the public interest under s. 44.2(3)(a) of the Utilities Commission Act (the "Act").

The Reasons address in the first instance, BC Hydro's method of seeking the Commission's approval for its Fort Nelson Generating Station Upgrade Project. Next, the Reasons address the current status of Fort Nelson in BC Hydro's service area; Fort Nelson's forecast load growth; BC Hydro's evaluation and analysis of options to meet that growth; BC Hydro's proposed solution and its attendant risks, including BC Hydro's obligation to consult and, if necessary, accommodate affected First Nations; and the impact of the Project on BC Hydro's ratepayers. Finally, the Commission Panel sets out its findings.

The Commission Panel finds that BC Hydro has met essentially the requirements set out in the Commission's Certificate of Public Convenience and Necessity ("CPCN") Guidelines in its s. 44.2(3)(a) request and that no purpose would be served by directing BC Hydro to apply under s. 45 (1) of the Act for a CPCN for this Fort Nelson upgrade. The Commission Panel accepts BC Hydro's load forecast for the Fort Nelson region. The Commission Panel considers that BC Hydro has adequately analyzed its options and that FNU3 is the most suitable option to meet BC Hydro's forecast of load at this time. The Commission Panel is satisfied, based on the record before it, that BC Hydro's consultation efforts with affected First Nations have been adequate to discharge the honour of the Crown to this state of the process.

Accordingly, the Commission Panel determines that, subject to a condition, BC Hydro's proposed expenditures of \$140.1 million to complete the definition phase work and implement FNU3 are in the public interest.

1.0 BC HYDRO'S APPLICATION

1.1 Order Sought

On June 12, 2008 BC Hydro filed its 2008 Long Term Acquisition Plan ("2008 LTAP") with the British Columbia Utilities Commission ("Commission") under s. 44.1(2), 44.1(4) and 44.2(1) of the Act. On October 24, 2008 BC Hydro filed its Fort Nelson Evidentiary Update (Exhibit B-1-10) and on December 22, 2008 it filed an Evidentiary Update for the 2008 LTAP which included an update of the 2007 Fort Nelson Load Forecast (Exhibit B-10).

BC Hydro requests, pursuant to s. 44.2(3)(a) of the Act, a determination that expenditures of \$140.1 million in F2009 – F2012 required to complete the definition phase work for, and implement, FNU3 are in the public interest. BC Hydro’s Senior Vice-President, Engineering, Aboriginal Relations and Generation (“EARG”), testified that FNU3 was the upgrade option that BC Hydro strongly preferred. He further testified that it was the primary option that was presented to the Board of Directors most recently in mid-September 2008 and that the plan was to seek final approval from its management and from its Board of Directors in May 2009 (T8:1447-1449).

In the alternative, BC Hydro seeks a determination that expenditures of approximately \$94.5 million to complete the definition phase work for, and implement, the Fort Nelson Generating Station Upgrade Project Case 2 (“FNU2”) are in the public interest under s. 44.2(3)(a) of the Act.

In response to a suggestion by the Panel Chair that in seeking alternative orders before the Commission it was “placing the regulatory cart in front of the management horse” BC Hydro testified “there’s a sense of urgency in Fort Nelson ... So there’s a real sense of urgency to get this project done, and for expediency’s sake we put it in the LTAP” (T6:856).

BC Hydro submits that an upgrade to the capability of its existing Fort Nelson Generating Station (“FNG”) is imperative, and by proposing FNU2 as an alternative, it seeks to establish, in one proceeding, what it would do in the event the Commission were to reject BC Hydro’s request with respect to FNU3, namely to resubmit a part of a LTAP that was rejected by the Commission. BC Hydro submits that a re-submittal, if required in this instance, would be a request for Commission approval of the lower capability FNU2 project, and that the request as set out accomplishes both stages without any loss in schedule.

At both the First Procedural Conference of September 9, 2008 (T2:85) and the Second Procedural Conference of November 27, 2008 (T2:114-115) counsel for BC Hydro put the parties on notice that BC Hydro proposed to request the Commission to make an early determination decision with respect to its proposed upgrade project. In Argument, BC Hydro requests the Commission issue a determination with respect to FNU3 or FNU2 no later than June 15, 2009, and submits that such an early determination would eliminate one of the two alternatives – FNU3 or FNU2 – early in its procurement strategy process, and would enable BC Hydro to achieve its required in-service date (“ISD”) of November 2011 (BC Hydro Argument, pp. 191-92).

1.2 The Need for a CPCN

BC Hydro submits that s. 45(2) of the Act deems BC Hydro (being a public utility that was operating a public utility plant or system on 11 September 1980) to have received a CPCN authorizing it to operate its plant and system that was in operation on that date, and to construct and operate subsequent extensions to that plant or system. BC Hydro states that the term “extension” does not refer just to additions to the geographic footprint of BC Hydro’s distribution and transmission lines

(i.e., increases in the size of its service area), but that it includes facility additions that increase BC Hydro's capability to provide service (as defined in the Act) within its service area.

BC Hydro submits that there is no reason for the Commission to direct it to apply for a CPCN for its proposed upgrade project, and points out that the amount of information filed in Appendix N1 and Appendix N2 of Exhibit B-1-10 and provided at the oral hearing is the equivalent amount of information required by the Commission to review a CPCN application, and is sufficient for the Commission to make the requested determination. In its following of the Commission's CPCN Guidelines, BC Hydro submits that it provided information concerning:

- Project description and impacts, including technical description, implementation schedule, social and environmental impacts;
- Project risk and risk management, including with respect to development, construction and commissioning (implementation) and operations;
- need and justification for the project, including a load/resource balance;
- information concerning the engagement and consultation process with the relevant First Nations;
- economic and ratepayer impacts, including capital cost estimates; and
- Project alternatives.

(BC Hydro Argument, pp.192-93)

When cross-examined on what the advantages and disadvantages would be of the Commission directing BC Hydro to apply for a CPCN for FNU3, BC Hydro testified that directing BC Hydro to apply for a CPCN would mean that the ISD of November 2011 could not be met (T8:1342-1343).

Only three intervenors comment on this issue of whether BC Hydro should have applied for a CPCN. CECBC agrees with BC Hydro's description of the FNGU-related expenditure determination request as a "CPCN-like" filing and supports BC Hydro's view that a CPCN for this project need not be required (CECBC Argument, p. 149).

IPPBC submits that it "reluctantly supports Fort Nelson Generating Station Upgrade 3even though the request for BCUC approval should have been advanced as an application for a certificate of public convenience and necessity and have received advance approval from BCH's Board of Directors" (IPPBC Argument, p. 18).

JIESC, on the other hand, submits that it “does not see the benefit of what BC Hydro describes as the FNRP [Fort Nelson Resource Plan] being a “CPCN-like” filing made under the subsection 44.2(1) (b) of the UCA if the same information is filed as would be for a CPCN and would discourage such applications in the future. The filing in the present manner appears to be an inappropriate use of section 44.2 and provides little benefit over filing pursuant to section 45(1) for a Certificate of Public Convenience and Necessity”. (JIESC Argument, p. 8)

At the Oral Phase of Argument, counsel for BC Hydro stated that BC Hydro’s Board of Directors had approved FNU3 (T16:2996).

2.0 CURRENT SUPPLY SITUATION

BC Hydro describes the Fort Nelson region as being unique on its system in that it is not directly connected to BC Hydro’s integrated system, but rather is electrically connected to the Alberta Interconnected Electric System (“AIES”) by a 144kV transmission line connecting Rainbow Lake in Alberta to Fort Nelson, and is part of the Alberta Electric System Operator (“AESO”) control area. BC Hydro observes that the combined region of Fort Nelson and Rainbow Lake (“FN/RB”) is relatively remote from major load centres in both B.C. and Alberta.

BC Hydro states that the 2007/2008 winter peak load was 28 MW on the B.C. side of FN/RB, and 103 MW on the Alberta side, for a total demand of approximately 131 MW. BC Hydro states that the load in the Fort Nelson area is normally met from FNG and the expected 2008/2009 peak load is 44.8 MW (before taking into account Canfor’s announcement to indefinitely close its two mills in the region). FNG is a simple-cycle natural gas-fired unit with a capability of 47 MW in the winter and 40 MW in the summer. By virtue of the interconnection with the Alberta system, FNG is available to provide energy and voltage support to Northwest Alberta.

BC Hydro states that it also has a demand transmission service agreement with the AESO, upon which it relies primarily for backup service to reliably serve the Fort Nelson area load when FNG is not operating. The agreement is a postage stamp-like tariff approved by the Alberta Utilities Commission.

BC Hydro describes the FN/RB region as being currently capacity constrained, which requires the generators in the region to be available to provide Transmission Must Run (“TMR”) services, and some customers to be available for load shedding. The AESO has operating procedures in place to manage the constraints. There will be a requirement for TMR generation in the region at least until the AESO completes its currently committed transmission upgrades in 2011 (Exhibit B-1-10, Appendix N1, pp. 10-12 of 166).

BC Hydro states that the combined transmission capacity into the region is currently capable of meeting 130 MW of FN/RB area load. However, to sustain this level of transmission capacity, an equivalent amount of generation must be provided as TMR in the region to meet the under voltage security requirements. This results in effectively no net import to the FN/RB region under normal conditions, notwithstanding the identified transmission capacity, with any load served above 130 MW currently being served on a curtailable basis. The AESO received approval from the Alberta Utilities Commission in August 2006 to upgrade transmission into the Alberta north-west (known as the Northwest Alberta Area Upgrade project (“AESO A0”)), the region that feeds FN/RB.

BC Hydro estimates that, given the forecast load growth on the Alberta side of FN/RB, and assuming approval and execution of FNU3 and AESO A0, the physical supply capability at the B.C./Alberta border to support Fort Nelson load supplied by BC Hydro is expected to be as shown in Table 5-3.

**Table 5-3 Transmission Capability available to
BC Hydro**

Year	2008	2009	2010	2011 ¹⁶
Firm (no TMR)	0.0	Gradually increasing to 28.5 ¹⁷		39
Firm (with TMR)	28.5	28.5	28.5	74
Curtailable	10.0	10.0	10.0	-
Total with Curtailable	38.5	38.5	38.5	74

Exhibit B-1-10, Appendix N, p. 31 of 166.

3.0 BC HYDRO’S LOAD FORECASTS FOR FORT NELSON

3.1 2007 Load Forecast

BC Hydro states that its Fort Nelson service area is part of the AIES, and is generally supplied by thermal generating resources and is capacity constrained rather than energy constrained. FN/RB is also transmission constrained both internally and externally to the AIES. Therefore, the predominant forecast for reliability planning purposes is the peak demand forecast, with the primary use of the energy demand forecast being to calculate the forecast cost of service, including local supply, imports and exports.

BC Hydro’s 2007 load forecast for Fort Nelson was included in Appendix D of the 2008 LTAP, as set out in the Table below:

Energy Load (GWh/year)	F2008	F2017	F2021	F2027
Sales	191	253	265	282
Generation	206	274	287	305
Peak (MW)	43	46	48	51

Source: Exhibit B-1, Appendix D pp.50-53 of 103

3.2 Fort Nelson Evidentiary Update

In its Fort Nelson Evidentiary Update dated October 24, 2008, BC Hydro updates its load forecast, basing its analysis on its 2007 Load Forecast ("Reference Forecast") along with the following three scenarios of possible load growth. Each scenario was developed using a bottom-up forecasting methodology based on information gathered, in confidence, from potential customers and assessed by BC Hydro as to the likelihood of the projects proceeding, and included discussions conducted in 2007 with several B.C. oil and gas development companies, or their competitors, and rough projections of future development in the sector:

- 1) a low scenario comprised of: (a) the Reference Forecast increased by 1 MW to reflect one or two small projects based on recent land tenure sales; and (b) potential load from six projects, each smaller than 5 MW, estimated by oil and gas developers from potential projects;
- 2) a mid scenario comprised of: (a) the Reference Forecast increased by approximately 6 MW, to reflect one large generic project; and (b) potential load from a few large projects, each greater than 5 MW, estimated by oil and gas developers from potential projects; and
- 3) a high scenario which was a compilation of the Reference Forecast plus the incremental loads described above for the low and mid scenarios.

(Exhibit B-3, BCUC 1.38.3)

Figure 5-1 below graphically represents the three scenarios:

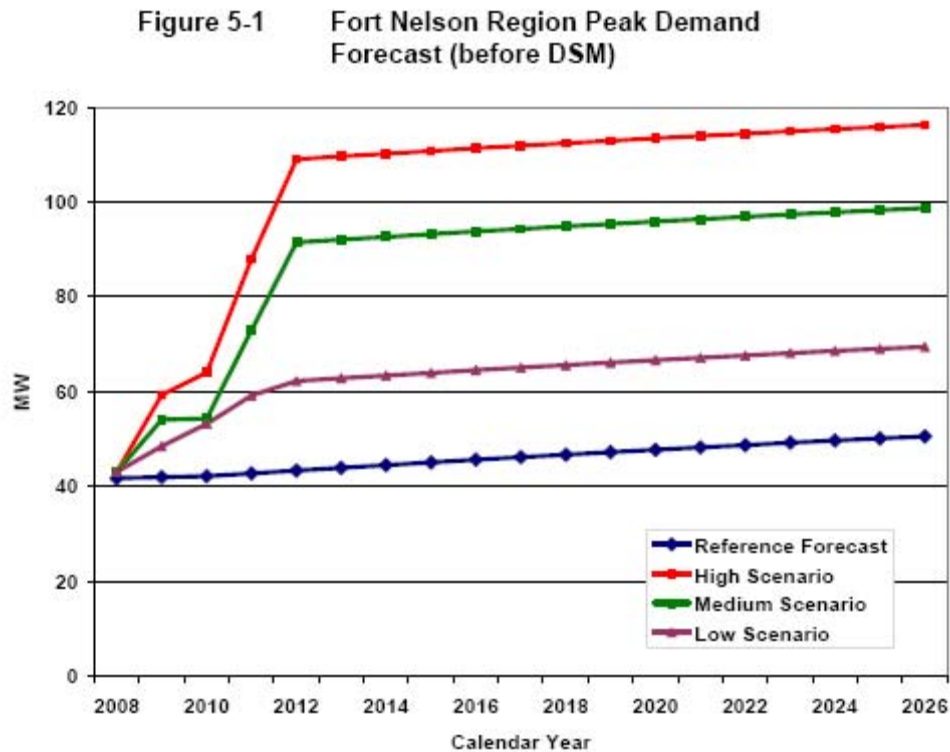


Exhibit B-1-10, Appendix N1, pp.22-24 of 166

BC Hydro states that after it prepared the Reference Forecast and growth scenarios, two significant customer-related events occurred, the first being that it obtained interruptible service from the AESO to serve a customer’s requested 10 MW of new service, and secondly, Canfor, a major forest products company, having announced the closure of its two mills in the Fort Nelson area, closed them indefinitely in June and October of 2008 respectively (Exhibit B-1-10, Appendix N1, p. 104 of 166).

BC Hydro states that neither the Reference Forecast nor the scenarios assume any reduction in load in Fort Nelson resulting from the indefinite closure of the Canfor mills. Each mill has a requirement of approximately 6 to 8 MW (Exhibit B-1-10, p.33 of 166), and BC Hydro noted that with respect to the decision to proceed with either option, the relevant time frame was 2012 and onward, and that both Canfor mills were included in the load forecast by that date (Exhibit B-12, Panel IR 1.5.2).

3.3 Demand Side Measures (“DSM”)

BC Hydro states that it has completed a Fort Nelson-specific forecast of the expected DSM savings that would be realized from the implementation of the measures in DSM Option A that it has proposed in the 2008 LTAP, and that expected electricity savings in the Fort Nelson region for the Reference Forecast by 2020 is 5.5 MW of demand and 37.9 GWh/year of

energy. BC Hydro states that it assumed that any additional DSM that may be available if the projects underlying the new loads in the low, mid and high scenarios do materialize will be incorporated in the design and implementation of those projects with the result that the load scenarios are effectively net of DSM potential (Exhibit B-1-10, Appendix N1, pp. 26-27 of 166).

3.4 2008 LTAP Evidentiary Update

BC Hydro states in its 2008 LTAP Evidentiary Update that it had completed its 2008 Load Forecast Update including an updated forecast for the Fort Nelson region, where events had led it to conclude that there will be a significant increase in the expected load largely due to increased oil and gas activity in the Horn River Basin. 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 and also received from the Canadian Association of Petroleum Producers (“CAPP”), on behalf of local member producers, a forecast of gas production and the associated expectation for electricity demand for the Horn River Basin region.

CAPP’s forecast provides two scenarios for the new compression and gas plant load that could be served by electricity:

- 1) CAPP’s High Case Load (~ 350 MW total) assumes power is available in 2011 and that all (120 MW) of the Cabin [gas processing] Plant is ultimately electrified, 90 MW of existing compression at raw gas treatment sites is retrofitted to electric drive, and 75 percent of the load growth from 2012 onwards (160 MW) is electrified; and
- 2) the Low Case Load (~ 100 MW total) assumes power is available in 2016, and that only 20 MW of Cabin Plant is ultimately electrified, existing compression at raw gas treatment sites is not retrofitted to electric drive, and 75 percent of the load growth from 2016 onwards (90 MW) is electrified.

(Exhibit B-10, Attachment 3, p. 5)

Given the data in the CAPP forecast, when combined with BC Hydro’s load forecast analysis BC Hydro states it has significantly increased its 2008 Load Forecast for the region (Exhibit B-10, p. 36).

BC Hydro states that it continues to advance the state of readiness of potential resource options to meet load growth above that which can be met with the 2008 LTAP Base Plan for Fort Nelson and describes the current status of its planning activities (Exhibit B-10, pp. 40-41).

BC Hydro states that it does not use the Load Forecast in the 2008 LTAP Evidentiary Update, and bases all its analysis on the low scenario in the Fort Nelson Evidentiary Update. As a result of presently having load that must be served on an interruptible basis, the number of inquiries for new load received recently, requests for interconnection studies, and public announcements on proposed oil and gas developments, BC Hydro believes the low scenario to be the prudent minimum load growth profile on which to commit to provide incremental supply capacity and energy, notwithstanding the lack of firm commitments for the potential new load. BC Hydro states that its economic analysis does not include the impact of

these possible new loads, but treats them subjectively in the risk analysis section (Exhibit B-1-10, Appendix N1, p. 25 of 166).

3.4 Intervenor's views

IPPBC submits that BC Hydro's forecast of the electricity requirements from oil and gas development in the Fort Nelson is inadequate, in that BC Hydro did not compile the customer contact and base information about the industry but waited for potential service requests to materialize. IPPBC suggests that a more proactive approach would have provided better results, noting that BC Hydro did not have any discussions with the BC Oil and Gas Commission in Fort St. John, which should have been "one of the starting points for an in depth analysis of the electricity requirements of the B.C. oil and natural gas industry" (IPPBC Argument, p. 18).

In its Reply, BC Hydro addresses IPPBC's submission and submits that its oil and gas industry working group is a continuation of a long series of dialogues with the industry going back well before 2008, which has included the major regional gas producers, pipelines and processors, government ministries and a number of sector experts/consultants. BC Hydro submits that "To imply that BC Hydro created its oil and gas sector load expectations on an uninformed basis is completely inaccurate" (BC Hydro Reply, p. 43).

JIESC submits that while it recognizes that the Horn River Basin may have substantial future load, it does not believe that a load forecast should be increased at this time to recognize Horn River Basin requirements. More importantly, JIESC does not accept that it is prudent for BC Hydro to acquire resources to provide service to the Horn River Basin under long term 20-40 year contracts at this time in the absence of firm customer commitments and evidence of long term demand. The size and other characteristics of the load in the Horn River Basin, and the amount that will be served by BC Hydro are still highly uncertain. Furthermore, the capability of BC Hydro to service a substantial new load at Fort Nelson is uncertain. To date, there is no requirement for conversion of natural gas-driven compression to electrically driven (to offset greenhouse gas emissions), and there is no transmission capability within BC to get the electricity to Fort Nelson (JIESC Argument, p. 34).

In its Reply, BC Hydro does not address JIESC's submission concerning Horn River. BC Hydro had previously stated that the "2007 Low Scenario did not include any load attributable to the Horn River Basin. Potential new load from the Horn River Basin or from any of what is generally referred to as unconventional gas, which consists of shale gas and tight sand gas, was only identified as a potential up-side load risk" (Exhibit B-12, Panel IR 1.8.1).

4.0 EXAMINATION OF ALTERNATIVES

4.1 Planning Objectives and Reliability Criteria

BC Hydro states that its main planning objectives are to meet its customer demand in a reliable and cost-effective manner, and that it plans to serve its customer demand in its Fort Nelson service area in the same way it does in the interconnected portions of its system. BC Hydro states that from a reliability perspective, the area is radially fed from Alberta and has a single generating unit, and that the primary criterion is based on the largest single contingency (or N-1) standard, which is to have sufficient resources available to meet the area load with the single largest element of the supply system (either the transmission line to the area or FNG) out of service (Exhibit B-1-10, Appendix N1, p. 18 of 166).

BC Hydro sets out Figure 5-6 to demonstrate that there is insufficient capacity currently available to reliably meet the customer demand. The Load/Resource Balance for 2008 shows there is a shortfall in supply of some 5 to 10 MW even if none of the new load growth considered in the Scenarios becomes a reality.

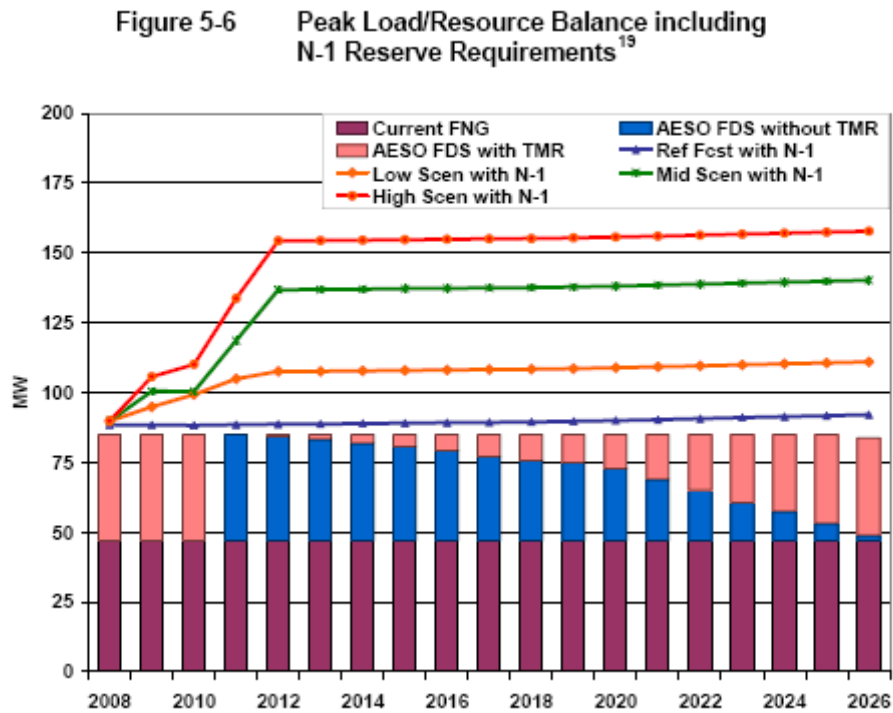


Exhibit B-1-10, Appendix N1, p. 33 of 166

4.2 Portfolio Analysis

BC Hydro states that it considered three general supply sources for portfolio analysis to meet Fort Nelson's long term load growth net of DSM:

- new local generation;
- additional supply from Alberta; and
- new transmission service from the BC Transmission Corporation ("BCTC") interconnected grid.

BC Hydro concludes that any supply plan would have to be based on one, or a combination, of these three sources.

BC Hydro states that its analysis starts from the base assumption that the existing FNG plus the selected transmission source (AESO first, then BCTC) will meet the load. In all cases, the forecast DSM savings have been netted from the forecast gross peak and energy demand. It considers curtailable load as an operational contingency option only, and does not consider it as a supply option in its analysis in the Fort Nelson Resource Plan. BC Hydro states it used combinations of generation resources and transmission resources to create 29 portfolios (Exhibit B-1-10, Appendix N1, pp. 54-55 of 166).

4.3 Generation Resources Considered

4.3.1 Resource Smart

BC Hydro states that it identified two Resource Smart projects ("FNU2" and "FNU3") both of which would convert the existing FNG Simple-Cycle Gas Turbine ("SCGT") installation to a Combined Cycle Gas Turbine ("CCGT"). Both project cases would involve upgrading the existing gas turbine and either upgrading or replacing the current heat recovery boiler to a once through steam generator ("OTSG"), and installing a new steam turbine generator ("STG") – the FNU2 project case. The FNU3 project case would see the addition of duct firing i.e. additional burners which provide supplementary energy to the OTSG to enable it to produce more steam and increase the output of the STG. FNU2 would provide approximately 10 MW of additional capacity from substantially the same amount of natural gas as is currently used at FNG, while FNU3 would provide approximately 26 MW of additional capacity, with additional natural gas being required for the duct firing (Exhibit B-1-10, Appendix N1, pp. 37-38 of 166).

Either FNU 2 or FNU 3 would deal with only a portion of the load/resource gap for FN/RB. The following sections deal with the longer term considerations for the region with growth above the Low Scenario.

4.3.2 New Supply

BC Hydro identifies the possibility of new CCGT capability in Fort Nelson as either an expansion of FNU2 or FNU3 or a new greenfield CCGT project of similar size, which could add approximately 55 to 75 MW of capacity but which would not be an alternative to upgrading FNG because a new CCGT would not be able to meet an ISD of F2012.

BC Hydro states that it has, for purposes of estimating the ISD for the two CCGT cases, assumed a two to three-year period for the engineering, procurement and construction. In the analysis, the new CCGT, called C57, is set to be the same size and performance characteristics as FNU2.

BC Hydro also developed an early investigative cost estimate for a 31 MW CCGT (at the FNG site or greenfield site), called C31 for the analysis (Exhibit B-1-10, Appendix N1, p.42 of 166).

4.3.3 Clean Power

BC Hydro states that in July 2007 it issued a request for expressions of interest (“RFEOI”) for the provision of clean or green electricity from Independent Power Producers in the Fort Nelson area and received a total of fifteen eligible responses: six bio-energy, two small hydro, six wind, one geothermal, and one pumped storage.

Since in the Fort Nelson region BC Hydro requires a reliable source of dependable capacity that is dispatchable and economically capable to produce energy at relatively high capacity factor, it considers that only the bio-energy projects could potentially provide this level of reliability in supply, and that, while the RFEOI results indicate a possibility of locating a wood waste biomass generating station in the area, it may not be dispatchable, and would be small. Accordingly BC Hydro’s analysis assumes a generic 10 MW biomass purchase contract, which plant would be available from 2012 through to the end of the study period, 2027; but would not be dispatchable (Exhibit B-1-10, Appendix N1, p. 45 of 166).

4.4 Transmission Resources Considered

4.4.1 Alberta

Beyond AESO A0 noted earlier, BC Hydro identifies the following transmission upgrades in Alberta which it has included in its portfolio analysis:

Transmission Upgrades in Alberta

Description	ISD	Capacity without TMR(MW)
AESO A1. Convert the new Wesley Creek to Hotchkiss double circuit line to 240 kV operation	2011	170
AESO A2. A1 plus extend 144kV single circuit Hotchkiss to Rainbow Lake	2013	200
AESO A4. A1 plus extend new double circuit line to Rainbow Lake	2013	350

BC Hydro states that it expects that AESO A1 will be developed by the AESO either based on internal Alberta requirements or as a result of BC Hydro's request for additional capacity as initiated by its preliminary assessment application and that if the AESO proceeds with this project, the increase in capacity could be available for 2011. This transmission expansion project is required if the AESO is to provide additional service to BC Hydro. Once upgraded, BC Hydro expects there to be approximately 64 MW in 2011 and 62 MW in 2012 available at the interconnection without requiring TMR. This capacity level declines as load grows in the Rainbow Lake region of Alberta (Exhibit B-1-10, Appendix N1, pp. 46-47 of 166).

4.4.2 British Columbia

BC Hydro states that connecting the Fort Nelson region with BC's integrated grid would require a 300 km high voltage line (called BCTC B1 in the analysis), likely 230 kV, to be constructed from the Peace River region to Fort Nelson. BC Hydro states that the 300 km distance to a major generating station is much shorter than a comparable interconnection in Alberta. The early investigation phase estimate of BCTC B1's cost is \$403 million with the expected earliest ISD being by 2015 (Exhibit B-1-10, Appendix N1, p. 52 of 166).

4.5 Timing

BC Hydro sets out the timing of its resource options in the following table:

Table 7-2 Timing of Resource Options

Option	Earliest ISD	Comment
AESO A1	2011	This is the quickest upgrade project available to meet possible near term load growth. It has a relatively low capital cost but very high losses.
FNU2 / FNU3	2012	This project has a relatively short lead time; it may have less scheduling risk because of its contained footprint.
AESO A2	2013	Earliest expected date for this option.
New CCGT: C57	2014	This project would be somewhat later than the FNGU, however, if constructed at the FNG site, there should be reasonably contained scheduling risks.
New CCGT: C31	2014	The lead time would be similar to C57.
BCTC B1	2015	This has a later ISD than all other alternatives.

Exhibit B-1-10, Appendix N1, p. 56 of 166

4.6 Economic Analysis

BC Hydro states that it performed an economic analysis on the time period 2012 through 2027, based on the assumption that all new resource options could be in service by 2012, and that it tested the cost, capability and performance characteristics of each resource when modelled in a portfolio that met the reliability criterion for some or all of the referenced time period (Exhibit B-1-10, Appendix N1, p.71 of 166).

BC Hydro calculates the PV of the various portfolios for the Reference Forecast and the three Scenarios across the range of electricity market price forecasts. The existing FNG is provided for reference with the main comparisons being of FNU2 against FNU3.

Table 7-10 Load Resource Balances for FNU3 vs. FNGC31

	AESO A0	AESO A1	AESO A2	AESO A0 + C57	AESO A1 + C57	BCTC B1
FNG	Sect. 10.1	Sect. 10.6	Sect. 10.11	Sect. 10.16	Sect. 10.19	Sect. 10.22
FNU2	Sect. 10.2	Sect. 10.7	Sect. 10.12	Sect. 10.17	Sect. 10.20	Sect. 10.23
FNU3	Sect. 10.4	Sect. 10.9	Sect. 10.14	Sect. 10.18	Sect. 10.21	Sect. 10.25

Exhibit B-1-10, Appendix N1, p. 77 of 166

BC Hydro sets out the PV of costs in the following Table:

Figure 7-11 PV of costs from 2012 through 2027 for Weighted Average Price Forecast

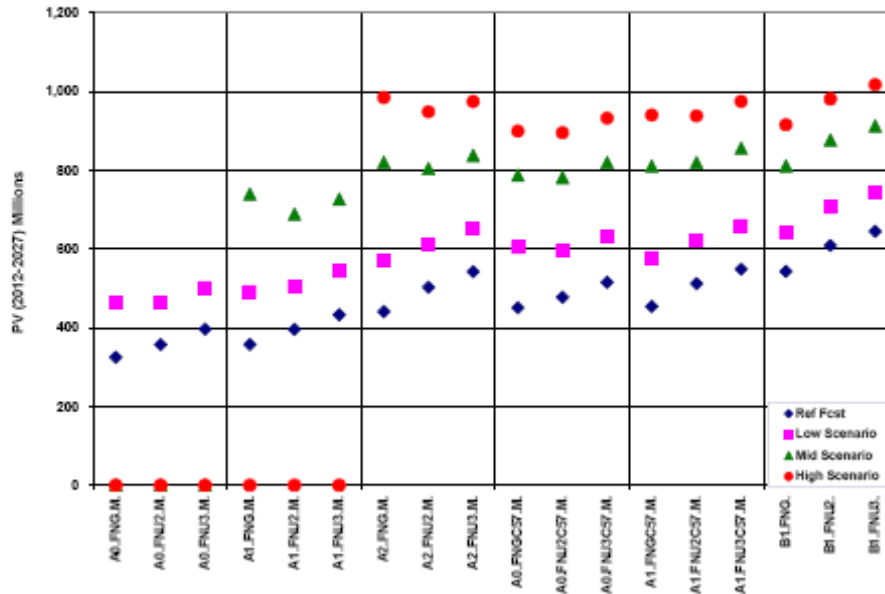


Exhibit B-1-10, Appendix N1, p. 79 of 166

BC Hydro concludes that its economic analysis shows that the portfolio of the FNU2 and FNU3 along with the AESO A1 are economic alternatives to increase the supply capacity and which demonstrate resilience to the identified risk factors. FNG, with no additional capacity, would have additional economic risk as compared to FNU2 or FNU3 as a result of the possibility of a requirement for GHG offsets on imports. The portfolio with FNU3 and AESO A0 is the lowest cost alternative that meets the full N-1 measure if loads were not expected to materialize above the low scenario. The portfolio with FNU3 and AESO A1 provides additional flexibility to economically meet some additional load above the low scenario.

BC Hydro proceeds to examine FNU2 and FNU3 in greater detail as discussed in the following Section.

5.0 COMPARISON OF FNU3 WITH FNU2

BC Hydro states that FNG was designed and constructed to accommodate a CCGT configuration, and that FNU3 will generate 70.5 MW at average annual conditions, while producing a maximum of 72.5 MW in winter peak conditions, whereas FNU2 will generate 54.4 MW at average annual conditions, while producing a maximum of 56.0 MW in winter peak conditions. A summary of the components of FNU2 and FNU3 are provided in Table 2-2.

Table 2-2 FNU2 and FNU3 components

Equipment	FNU2	FNU3
Gas Turbine:	New GE LM 6000 DLE PD 43.9 MW	New GE LM 6000 DLE PF 43.7 MW
Generator:	Existing 47 MW Alstom (nominal rating)	Existing 47 MW Alstom (nominal rating)
Duct Firing (DF):	N/A	DF to a gas temperature of 727°C with a new 5.8 metre duct extension using new tube material required for the higher temperature
OTSG:	New or upgraded OTSG to deliver maximum steam production from waste heat of the gas turbine	New or upgraded OTSG to maximize the steam pressure and temperature
Steam Turbine Generator:	11.8 MW Nominal rating	28.4 MW Nominal rating
Capability:	54.4 MW Net annual average	70.5 MW Net annual average

Exhibit B-1-10, Appendix N2, p.2-10

5.1 Project Capital Cost Summary

BC Hydro estimates the cost for FNU3 to be \$140.1 million (\$2012 +35 percent/-15 percent) and for FNU2 to be \$94.5 million (\$2012 +35 percent/- 15 percent). Table 2-7 contains the cost details for both FNU3 and FNU2.

**Table 2-7 Summary of Project Feasibility Costs
(+35 per cent/-15 per cent)**

Description	FNU2 (\$ Million)	FNU3 (\$ Million)
Project Cost Estimate (direct and some indirect costs) (\$2008)	54.1	80.0
Contingency ¹⁴	10.9	16.0
Escalation ¹⁵	6.0	8.6
BC Hydro Overhead	9.4	13.9
Interest During Construction	8.1	11.6
Project Estimate without Reserve (P50) (\$2012)	88.5	130.1
Recommended Project Reserve ¹⁶	6.0	10.0
Expected Project cost	94.5	140.1
Project Cost Range (\$2012)	80 - 128	119 - 189
Capital Cost (\$ Million/MW)	10.3	5.3

Exhibit B-1-10, Appendix N2, p.2-16

5.2 Schedule

BC Hydro states that it is working to an ISD of November 2011 for either FNU3 or FNU2, with the same project schedule for FNU2 as for FNU3 except the gas turbine outage for FNU3 is estimated to be six weeks in duration compared to FNU2 at four weeks in duration. BC Hydro is in the process of issuing tenders for the long lead-time equipment such as the STG. BC Hydro intends to award contracts for STG and other equipment as soon as the Commission determines that the requested FNU3, or in the alternative, the FNU2 expenditures are in the public interest.

5.3 Emissions

BC Hydro sets out the estimated NOx emissions and stack flows for FNG, FNU2 and FNU3 for average annual conditions in Table 2-5 and states that the air emission permit (PA-15854) for FNG, issued on March 12, 1999 by the B.C. Ministry of Environment ("MOE"), regulates two parameters; NOx as an hourly average (at or below 48 mg/m³) and total stack rate of discharge (at or below 107 m³/s). BC Hydro states that both NOx and stack flow for FNU2 and FNU3 will be below the existing air emission permit levels. The MOE's emissions criteria for turbines provide recommended limits for carbon monoxide ("CO") in the exhaust gases of a CCGT. As assurance for when FNU3 is operated without duct firing, equipment will be installed if necessary to keep the CO values below the MOE criteria. The costs associated with CO reduction

measures are included in the current feasibility phase cost estimates, and if not required would result in a lower overall final FNU3 cost.

**Table 2-5 NOx Emissions and Stack Flows
(Average Annual Conditions)**

	Units	MOE Criteria	Air Emission Permit	FNG	FNU2	FNU3 ¹²	FNU3 w/o Duct Firing
NOx	mg/SDm3 at 15% O2 (Vol)	48	48	46	48	36	29
Stack Flow	SDm3/s		107	104	100	100	97
CO	mg/SDm3 at 15% O2 (Vol)	58 ¹³		31	29	50	<58

Exhibit B-1-10, Appendix N2, p. 2-13

BC Hydro sets out the GHG emissions for the annual average conditions and the net capacity for FNG, FNU2 and FNU3 in Table 2-6, and states that while the GHG intensity for FNU2 and FNU3 will be lower than for FNG, but because FNU3 uses more natural gas to produce some of the additional energy, the total GHGs emitted from FNU3 when duct firing will be higher than the GHGs emitted by FNG.

Table 2-6 GHG Emissions

	Units	FNG (base)	FNU2	FNU3 ¹²
GHG	t/GWh	482	398	431
GHG from base	% change (t/GWh)		-17	-10
GHG	t/year	171200	168000	235800
GHG from base	% change (t/year)		-2	+38

Exhibit B-1-10, Appendix N2, p. 2-13

BC Hydro states that the duct firing portion of FNU3 will be operated in a similar fashion to a peaking unit, and accordingly the FNU3 GHG emissions are expected to be lower than shown in Table 2-6.

BCSEA expresses concern that upgrading the gas-fired generation facility in Fort Nelson will necessarily increase B.C.'s emission of GHGs, certainly in a physical sense, and submits that it is important that, at the least, BC Hydro provide GHG offsets for incremental GHG emissions due to expansion of the Fort Nelson plant as soon as the expanded plant comes into operation (BCSEA Argument, para. 129).

In its request for submissions in argument on certain matters, the Commission's Issue No. 3 stated: "Section 44.1(8) of the Act states that "in determining under s. (6) whether to accept a long-term resource plan, the commission must consider (a) "the government's energy objectives", which are defined as including "to encourage public utilities to reduce greenhouse gas emissions". In light of this would the approval by the Commission of FNU3 contravene such an instruction?" (Exhibit A-21)

In response, BC Hydro submits that conversion of FNG to FNU3 is a pragmatic response to the government's energy objective of encouraging public utilities to reduce GHG emissions, pointing out that the combined cycle portion of FNU3 will produce more electricity for the same or reduced total GHG emissions, and that the duct firing portion will be used when required for reliability or to offset imports. BC Hydro submits that the energy produced by the duct firing portion of FNU3 will have lower GHG per unit of energy than the imports it would displace, particularly after reflecting the energy losses to deliver electricity from Alberta to Fort Nelson, and that BC Hydro's portfolio analysis demonstrated that the conversion to either FNU2 or FNU3 from its current simple cycle arrangement reduced the cost risk associated with GHG (BC Hydro Argument, p. 187).

In support of this position, CECBC submits that "it would be contravening instruction if the Commission approves FNU3, and the evidence otherwise indicated approval of FNU3 was contrary to the objective and there is a reasonable alternative which is more consistent with the Government's energy objectives" (CECBC Argument, p. 149).

5.4 Other Applications and Approvals

BC Hydro states that neither FNU2 nor FNU3 will trigger a formal environmental assessment process under either the *Canadian Environmental Assessment Act* ("CEAA") or the *B.C. Environmental Assessment Act* ("BCEAA").

FNG only has one permit from the MOE (air emission permit PA-15854). Fresh process water and effluent are handled through a Water and Effluent Treatment Services Agreement with Spectra, which operates an adjoining gas plant which is referenced in the air emission permit. Fresh process water is also provided through an agreement with Spectra.

BC Hydro submits that neither FNU2 nor FNU3 will have significant adverse environmental or socio-economic impacts, and anticipates that any such impacts can, in general, be either avoided or minimized through mitigation measures. BC Hydro states that costs for such mitigation measures are included in the current feasibility phase cost estimates for both FNU2 and FNU3 (Exhibit B-1-10, p.2-18).

6.0 OPTION CHOSEN

6.1 Reasons for Selection

BC Hydro states that FNU3 is the only alternative available that can at satisfy the Fort Nelson region load to full N-1 and local supply security by 2012. At 72.5 MW peak winter rating, it is approximately 10 MW larger than the low scenario minimum supply requirement for that year. Further, it performs reasonably well in the economic analysis, it is dispatchable, and is resilient against a number of risk factors, including capital cost. When combined with the AESO A1, there is additional capacity to economically meet some additional load above the low scenario.

BC Hydro states that while the incremental cost of FNU3 in levelized \$/MWh terms is in the order of 5 \$/MWh to 10 \$/MWh higher than that for FNU2, the increased capacity and flexibility of FNU3 make it a better option to proceed with than FNU2. FNU3 does not show any materially adverse features that would result in BC Hydro concluding it would be more appropriate to relax the reliability measure to Partial N-1, develop FNU2 and start developing an alternative resource to replace the incremental capacity that would have been supplied by FNU3. There is relatively low risk that the upgrade will become stranded. FNU3 is a CCGT with some peaking capacity which provides flexibility even if the plant were to fill a reserve or backup role in future (Exhibit B-1-10, Appendix N1, p. 93 of 166).

BC Hydro submits that FNU3 has approximately 16 MW of peaking capacity, through its duct firing capability, available to operate when economic or to meet peak or contingency conditions when required for reliability or security purposes. While this comes at an additional cost, the economic analysis shows FNU3 to be sufficiently close to FNU2 that BC Hydro considers the added capacity makes the FNU3 option a better solution.

BC Hydro points to its response to Panel IR 1.17.1, and submits that the portfolio with FNU3 has a present value of \$543 million (\$2012) versus \$504 million (\$2012) for the portfolio with FNU2, which works out to an incremental cost for FNU3/AESO A1 of approximately \$3 million per year over the cost of FNU2/AESO A1 and provides an additional 16.1 MW of capacity. BC Hydro submits that FNU3 is its preferred upgrade to FNG (BC Hydro Argument, p. 187).

6.2 Project Risk

BC Hydro considers the risks associated with FNU3 within the three phases of the FNU3 project, being development, construction and commissioning, and operation.

6.2.1 Development Phase

BC Hydro states that development risks relate to confirming the viability and acceptability of FNU3 from technical, economic, environmental, First Nation and social perspectives, and that the costs have been defined to a Feasibility phase level of accuracy of +35 / -15 percent. BC Hydro considers this to be appropriate cost range for the development phase since more accurate cost estimates cannot be determined until the conclusion of competitive tendering, detailed design and other activities. BC Hydro states that it retained AMEC to prepare the project cost estimates and that it reviewed AMEC's cost estimates. And as a result, the technical and economic risks for FNU2 and FNU3 at this stage of the project's development have been defined and mitigation measures are in place.

BC Hydro states that risks related to environmental, First Nations (see Section 7.1 below) and social/community perspective (see Section 7.2 below) are low, noting that there is no formal environmental assessment process required, the potentially affected First Nations have raised no concerns or opposition to the FNG upgrade. BC Hydro submits that stakeholders are supportive as shown by the Town of Fort Nelson and the prophet River First Nation letters of support. The residual risks associated with these development risks are related to the determination sought from the Commission and the air emission permit minor amendment not being secured in a timely manner (Exhibit B-1-10, Appendix N2, p. 2-23).

6.2.2 Construction and Commissioning (Implementation) Risks

BC Hydro identifies the implementation risks for FNU3 as being related to the construction and commissioning of FNU3 and potential for project cost overruns and or schedule delays which could result in not achieving the November 2011 ISD, and states that its experienced project team, which includes outside industry expertise that will be engaged to manage the implementation of FNU3, will also manage the project to keep within the estimated project cost. Additionally, BC Hydro works with equipment suppliers and other contractors to mitigate supplier/contractor counterparty risks.

BC Hydro identifies a significant project risk as being related to the tendering and contracting for the STG. BC Hydro's current plan for procurement of the STG is to issue tenders by November, 2008, and allow a six to eight weeks tender period to mid-January for vendor responses. Tender evaluation is expected to take six to eight weeks, depending on the need for clarifications and degree of non-compliance with tender conditions. This would allow identification of a recommended supplier by mid-March, and the STG could be ordered at any time after BC Hydro Board approval. However no equipment will be purchased in advance of the Commission's determination (including selection of the preferred

alternative). BC Hydro will consider what arrangements need to be in place in the Request for tenders to ensure that tendered prices remain valid for an extended term – if the award cannot be made until June 2009 the Tender validity period would be approximately 180 days, as compared to a more common period of 90 days. Although the exact mechanism has not been identified, it is likely that BC Hydro will have to accept some risk of price fluctuations based on materials costs and currency movements between the Tender closing date and the date of award. Most of the activities on the schedule are now on the critical path, and the lead time (long delivery time) for ordering the STG and the other major equipment must be completed before June 2009 if the ISD is to be maintained (Exhibit B-1-10, Appendix N2, pp. 2-23/24).

In the Oral Phase of Argument, pursuant to item 7 of Exhibit A-20, counsel for BC Hydro stated that BC Hydro had no objection to the filing of quarterly progress reports, or to the filing of a final report within six months of the end or the substantial completion of the project, that will provide a "complete breakdown of the final costs of the project, compare those costs to the updated cost estimate, and provide a detailed explanation and justification of all material cost variances" (T16:2995).

6.3 Operations

BC Hydro states that following commissioning, the operation and maintenance of FNU3 will be managed by the staff at FNG, and that other than the major operational risks of natural gas and GHG prices, the operating risk is that FNU3 does not perform up to the designed capacity. Since FNU3 is a CCGT, a technology widely used for electricity generation, using proven technology, supplied by qualified and experienced equipment manufactures, BC Hydro is of the view that the likelihood of FNU3 not meeting the design capacity is low. However, BC Hydro will, through contractual agreement, further minimize the risk of FNU3 not achieving its design ratings (Exhibit B-1-10, Appendix N2, p. 2-25).

6.4 Risk of Stranded Investment

BC Hydro addresses the risk of stranded investment and states that the selected design and layout will be developed for FNU3 such that equipment or capital investment will not require major modification or demolition to integrate a future expansion. New equipment placement would not hamper an expansion of a size similar to the upgraded FNG should there be a future decision to add a second CCGT for increased capacity (Exhibit B-1-10, Appendix N2, p.2-25).

BC Hydro states that if BCTC's interconnection proceeds, it expects FNU3 to take on a local area TMR role, a contingency role, or some combination of the two over time. The interconnection appears to be an option that would be of value if there was relatively high load growth (at or above the High Scenario) in the Fort Nelson region, and if it proceeded, FNU3 as well as other assets would be considered as part of the design optimization. FNU3's capacity would provide significant support in the event of BCTC line outage, and should reduce the possible need for a second backup unit. (Exhibit B-1-10, Appendix N1, pp. 97/98 of 166)

7.0 FIRST NATIONS AND PUBLIC ENGAGEMENT

7.1 First Nations

In Argument, BC Hydro addresses the statement by the British Columbia Court of Appeal at paragraph 59 in *Kwikwetlem First Nation v. British Columbia (Utilities Commission)* 2009 BCCA 68 (“*Kwikwetlem Decision*”) that “certification under section 45 of the *Utilities Commission Act* is the vital first step toward the building of the transmission line across territory to which First Nations assert title and stewardship rights, one that, for practical reasons, BCTC, BC Hydro and the Commission consider necessarily precedes acceptance of an application for the required minister’s EAC”. BC Hydro observes that this wording suggests that definition phase-related expenditure determinations filed pursuant to s. 44.2(1) of the Act do not trigger, but that Major Threshold Project implementation filings may trigger, the *Kwikwetlem Decision*. Despite this observation, BC Hydro submits that the reasoning of the *Kwikwetlem Decision* applies to the FNU3 expenditure determination request filing because it is a Major Threshold Project implementation filing that is “CPCN-like” in nature. BC Hydro further submits that as of the date of its Argument, the relevant First Nation entities - Prophet River First Nation, Fort Nelson First Nation and the Treaty 8 Tribal Association - have raised no opposition to FNGU nor have they expressed a preference for one configuration alternative over another and also references section 7.6 of its Argument for a description of the evidence regarding consultation regarding the upgrade of FNG to date. (BC Hydro Argument, pp. 74-75).

The following describes BC Hydro’s consultation to date with potentially affected First Nations. As noted by BC Hydro in its Argument, the evidentiary record of First Nations engagement consultation with the Fort Nelson and Prophet River First Nations and with the Treaty 8 Tribal Council Association is set out in section 2.7.2 of Appendix N2 of Exhibit B-1-10, Exhibit B-54, Exhibit B-78 and the evidence of BC Hydro’s Senior Vice-President of EARG who testified on BC Hydro’s consultation activities with affected First Nations during his testimony as a member of BC Hydro’s Load/Resource Balance and Fort Nelson witness panel.

In section 2.7.2 of Appendix N2 of Exhibit B-1-10, BC Hydro provided the following information on First Nations engagement consultation.

BC Hydro states that FNG lies within the Treaty 8 area and that the two local Treaty 8 First Nations are the Fort Nelson and the Prophet River First Nations. BC Hydro has initiated an engagement/consultation process with First Nations whose interests may be affected by FNU3. BC Hydro indicated to both First Nations its willingness to facilitate their participation in consultation activities, including review of documents. In addition to documentation already provided, BC Hydro will share draft BC Hydro environmental assessment study reports, and updates and supporting documentation related to the BCUC regulatory review process.

Meetings were held with representatives of the Prophet River First Nation and the Fort Nelson First Nation on May 1, 2008 and May 26, 2008, respectively to provide a preliminary opportunity to identify risks, concerns, and uncertainties regarding the FNG upgrade.

BC Hydro states that the second phase of the engagement/consultation process began in summer 2008, is ongoing and seeks to provide the two local area First Nations with more detailed information concerning the FNG upgrade, including opportunities to participate in BC Hydro's environmental assessment studies. This will enable the First Nations to determine whether the project might have impacts on their rights or interests. To this end, meetings were held with representatives of the Fort Nelson First Nation and the Prophet River First Nation on July 2 and July 3, 2008, respectively. In advance of these meetings, the First Nations were sent a written summary of project information. Both First Nations were also invited to participate in a site visit to FNG but declined. Information was presented and Treaty 8 Tribal Council Association has been notified of the consultation process and is being copied on all project correspondence to the Fort Nelson First Nation and the Prophet River First Nation.

BC Hydro states that following the July 2 and 3, 2008 meetings, draft work plans and terms of reference for various BC Hydro environmental and social assessment studies were shared with the First Nations for their input, in particular the Archaeology Overview and Impact Assessment; Vegetation, Wildlife and Surface Water Surveys; Socio-Economic Impact Assessment; and Stage 1 Preliminary Site Investigation. Based on input received from the Prophet River First Nation, the vegetation surveys were designed to incorporate traditional medicinal plants.

Booklets produced by the First Nation helped to inform this component of the study and two Prophet River First Nation elders participated in the field work. With regard to the Archaeology Overview and Impact Assessment, the two First Nations were solicited for their recommendation as to a preferred archaeological consultant. The Prophet River First Nation put forward a preferred archaeologist and BC Hydro acted upon their recommendation. In addition, a member of each the Fort Nelson First Nation and the Prophet River First Nation participated in the field work for the archaeological assessment.

BC Hydro states that to date, First Nations have raised no concerns or opposition to the upgrade to FNG, have demonstrated recognition of the supply issues facing the region, and have acknowledged that the project is in their interests as FNG supplies their communities.

BC Hydro included a letter of support for the project from the Chief of the Prophet River First Nation. The letter further states that the [Prophet River First Nation] Council also supports the environmental assessments being undertaken and the three options that were provided by BC Hydro. (Exhibit B-1-10, Appendix N2, Attachment 3)

The Fort Nelson First Nation has indicated that it will be further considering potential project impacts and will advise of any additional feedback. To date, neither First Nation has expressed a preference for one configuration alternative over another, although the Prophet River First Nation has indicated that its support of the FNG upgrade includes support for all of the alternatives presented. The consultation process going forward will be the same regardless of the alternative selected.

BC Hydro submits that the record clearly demonstrates that BC Hydro's consultative efforts with First Nations have been adequate to discharge the honour of the Crown to this stage of the process. BC Hydro is asking the Commission to determine which of the alternatives for serving the Fort Nelson area should proceed and notes that no First Nation has indicated a preference for one alternative as opposed to another despite ample opportunity to do so. Consultation with respect to the selected alternative will continue and the air emission permitting process will determine the adequacy of that additional consultation. In these circumstances, the Commission has ample evidence on which to determine that, even on the broadest reading of its duties as explained in the Court of Appeal's *Kwikwetlem Decision*, the scope and extent of consultation conducted to date is adequate to permit the Commission to grant the relief sought by BC Hydro (BC Hydro Argument, p. 190).

CECBC endorses BC Hydro's description of its engagement and consultation with First Nations as appearing to be appropriate and notes that the consultation will be ongoing (CECBC Argument, p. 44).

7.2 Public Engagement

BC Hydro states that the first phase of the engagement/consultation process began in spring 2008, in the context of the 2008 FN RP/LTAP. These activities included meetings on April 30 and May 1, 2008 with First Nations and community groups, and an Open House which was held on April 30, 2008. BC Hydro presented facts and an overview of FNG and the reasons for BC Hydro's proposal to upgrade FNG, and the results expected from such an upgrade.

The second phase of the engagement/consultation process began in summer 2008 and is ongoing. On July 2 to 4, 2008 BC Hydro met with government agencies and stakeholders. BC Hydro reiterated the reasons for the upgrade to FNG, expanded on the upgrade options under consideration, its environmental assessment studies, and the estimated schedule for FNG upgrade implementation (Exhibit B-1-10, Appendix N2, p. 2-18).

The Regional Council for Fort Nelson and the Northern Rockies submitted a letter to express its strong support for BC Hydro's proposed upgrade to the Fort Nelson Generating Station (Exhibit B-1-10, Appendix N2, Attachment 4).

8.0 IMPACT OF THE PROJECT ON BC HYDRO’S REVENUE REQUIREMENTS

BC Hydro calculated that the incremental revenue requirement caused by FNU2 and FNU3 in their first year of operations would be \$9.2 million and \$21.8 million respectively. The following table sets out the revenue requirement and the revenue BC Hydro would receive if all the output was sold to a single customer taking service on Rate Schedule 1211 and on Rate Schedule 1823.

The last two lines of the table show the present value of the difference between the incremental revenue requirement and the incremental revenue which would need to be made up by “other ratepayer[s]”.

(\$000)	FNU2	FNU3
Revenue Requirement	9,226	21,795
Revenue (RS 1211)	3,732	8,843
Revenue (RS 1823)	2,991	7,028
PV of deficit (RS.1211)	18,447	70,611
PV of deficit (RS 1823)	25,505	87,914

Source: Exhibit B-56

Exhibit B-56 was an issue that the Commission Panel included on its agenda of the Oral Phase of Hearing [Exhibit A-20]. Counsel for BC Hydro described Exhibit B-56 as a “simplified analysis...it only looks at incremental generation created by the plant without looking at imports or import costs;... [and], without looking at what the alternative power source would be absent the upgrade” (T16:3000).

The three ratepayer intervenor groups addressed the potential cross-subsidization of industrial customers in Fort Nelson by residential and commercial customers elsewhere raised by Exhibit B-56. Counsel for JIESC submitted that “The government has indicated so far that new loads in the province, whether they be residential, commercial or industrial, get to share in the value of the Heritage Assets. In our submission it appears to be the correct policy” (T16:3002). Counsel for CECBC and BCOAPO supported this submission.

IPPBC submits that it “reluctantly supports Fort Nelson Generating Station Upgrade 3 at a price of \$140.1 million ... In this instance it is a matter of urgent need. To supply and retain the additional load that needs to be served until the transmission line is completed, BCH should use temporary natural gas fired generation” (IPPBC Argument, p. 18).

JIESC supports the FNU3 project to increase the capability of BC Hydro to serve existing and known potential customers in the Fort Nelson area (JIESC Argument, pp. 34-35).

CECBC supports BC Hydro's requested order with respect to FNU3 (CECBC Argument, p. 44).

While noting BC Hydro's evidence that expansion of Fort Nelson plant is required even in the event that new transmission is developed to link the Fort Nelson region to the integrated grid within B.C., BCSEA takes no position on BC Hydro's Fort Nelson expenditure request (BCSEA Argument, para. 130).

COPE submits that it "does not take any particular position with respect to the relief sought by BC Hydro in connection with the Fort Nelson Upgrade..." (COPE Argument, para. 130).

9.0 COMMISSION DETERMINATION

The Commission Panel accepts BC Hydro's argument that it need not seek a CPCN for its Fort Nelson upgrade and that its request for approval of the expenditure has been made in a "CPCN-like" fashion. Accordingly the Commission Panel has applied its guidelines for CPCNs in determining whether or not to approve BC Hydro's request. In doing so, the Commission Panel has considered whether BC Hydro has established the need for capacity additions, what options it identified, the selection it made from the choice of options, its proposal to develop the project and manage its risks and whether its consultation efforts with affected First Nations to this point have been adequate.

The Commission Panel accepts BC Hydro's load forecast for the Fort Nelson region, and BC Hydro's submission that the low scenario is the suitable forecast upon which to plan its new supply in the region. The Commission Panel rejects IPPBC's submission that consultation between BC Hydro and the potential customers in the Fort Nelson area was inadequate as not being supported by the evidence.

The Commission Panel finds that BC Hydro identified the cost-effective options available to it in the Fort Nelson area and has analyzed them realistically. The Commission Panel agrees that FNU 2 and FNU 3 are the most cost-effective options available to BC Hydro to meet the load growth in the projected time frame. The Commission Panel accepts BC Hydro's submission that while FNU2 offers a lower levelized cost per MWh than FNU3, FNU3 offers additional capacity to meet the low-load scenario, as well as additional flexibility, at a reasonable increment of cost over FNU2. The Commission Panel accepts BC Hydro's plans to mitigate the risks it has identified.

On the evidence before it, the Commission Panel is satisfied that BC Hydro's consultation efforts with affected First Nations have been adequate to discharge the honour of the Crown to this stage of the process.

The Commission Panel is satisfied that FNU3 complies with the government's energy objectives as set out in s. 1 of the Act, and accepts BC Hydro's submission that FNU 3 will produce less incremental GHG emissions than imports from Alberta or on-site generation.

Accordingly the Commission Panel determines that subject to the filing by BC Hydro of a copy of the resolution of BC Hydro's Board of Directors approving FNU3 with the Commission, the **expenditures of \$140.1 million in F2009 – F2012 required to complete the definition phase work for, and implement, FNU3 are in the public interest.**

Further, BC Hydro is directed to file with the Commission quarterly project reports and a final report within six months of project completion, in a format to be agreed by Commission staff and BC Hydro.