Integrated Resource Plan

Appendix 2E

Fort Nelson Supply and Electrification of the Horn River Basin Resource Plan Analysis Details

Table of Contents

List of Figures

List of Tables

1 Introduction

The Fort Nelson region is located within BC Hydro's service area in the far Northeast of B.C. The region is electrically integrated with Alberta's system via a single 144 kV transmission line and is not directly connected to the BC Hydro integrated system. The region includes electrified communities located within the Northern Rockies Regional Municipality[1] as well as industrial customers located along the 144 kV transmission corridor linking Fort Nelson to the Alberta system.

The Horn River Basin (**HRB**) region encompasses a large geographic area generally extending north and east of the community of Fort Nelson. It is a region with significant natural gas reserves. The natural gas reserves are called "unconventional" in that they are situated in shale formations and take new, more aggressive, techniques (i.e., "fracking") to extract the gas. BC Hydro currently serves the Fort Nelson region, but not the HRB.

This IRP analyzed various load scenarios and resource supply options for serving the combined Fort Nelson/HRB region electricity supply requirements, or (where applicable) each of the Fort Nelson region and/or HRB region separately.

The following sections describe:

- Fort Nelson supply planning, including current and future load projections; current supply mix, including transmission service from Alberta; and resource options for serving future load growth absent electrification of the HRB
- Horn River Basin supply planning, including a description of the electrification drivers, load potential and associated risks and uncertainties
- The alternative strategies and analytical approach for providing electricity service to the Fort Nelson/HRB regions

[1] The Northern Rockies Regional Municipality was incorporated in 2009, comprised of the former Town of Fort Nelson and the former Northern Rockies Regional District.

- The results of the analysis

2 Fort Nelson Supply Planning

2.1 Background

BC Hydro serves customers in the Fort Nelson region with:

- electricity generated at its recently upgraded 73 MW combined-cycle gas turbine (**CCGT**) plant, the Fort Nelson Generating Station (**FNG**)
- 38.5 MW of "Fort Nelson Demand Transmission Service" (**FTS**) from the Alberta Electric System Operator (**AESO**)

FNG is a natural gas-fired facility located 16 km south of the town of Fort Nelson. The current power plant is configured as a CCGT with an Alstom generator directly coupled to a General Electric (**GE**) LM6000 gas turbine and a Brush generator driven by a steam turbine. The gas turbine's rated capacity for normal operation is 47 MW and the steam turbine generator's rated capacity is 26 MW for a total plant capacity of 73 MW.[2]

BC Hydro currently receives transmission service from the AESO at the B.C./Alberta border (the interconnection point). It is available to BC Hydro at all times; when used, BC Hydro purchases the energy from the AESO electricity market at market-based rates. This transmission service is provided under the AESO's FTS rate schedule contained in the AESO's tariff.

The Northwest region of Alberta (Rainbow) is currently capacity constrained. Historically, the AESO has relied on generators located in the Rainbow and Fort Nelson areas to supply transmission-must-run[3] (**TMR)** services to the region and on the availability of some customers for load shedding. BC Hydro's electricity

[2] Winter capacity of FNG is now 73 MW. It is lower in summer (about 63 MW).

[3] TMR is another name for "Reliability-Must-Run", RMR, that is generating capacity that must run due to a transmission constraint.

marketing subsidiary, Powerex, presently markets FNG surplus electricity to the AESO through a Supply Transmission Service (**STS**) agreement. The electricity sales into the Alberta market are at non-regulated market-based rates. The STS is also provided under the AESO's tariff rate schedule. Until mid-2012, Powerex provided contracted TMR services to the AESO under a separate agreement. However, changing market conditions and the advent of the Northwest Alberta Transmission Development (**NWATD**) project completion (anticipated in December 2013) have significantly reduced the prospect for provision of TMR services in the region. The AESO also has operating procedures[4] in place to manage the constraints.

In addition, until the NWATD project is completed, the 38.5 MW FTS supply must be reduced by up to 10 MW within 20 minutes for certain contingencies in Alberta. Once the NWATD project is completed BC Hydro will be able to serve up to 38.5 MW of load in the Fort Nelson area on a firm[5] basis (N-1 reliability).

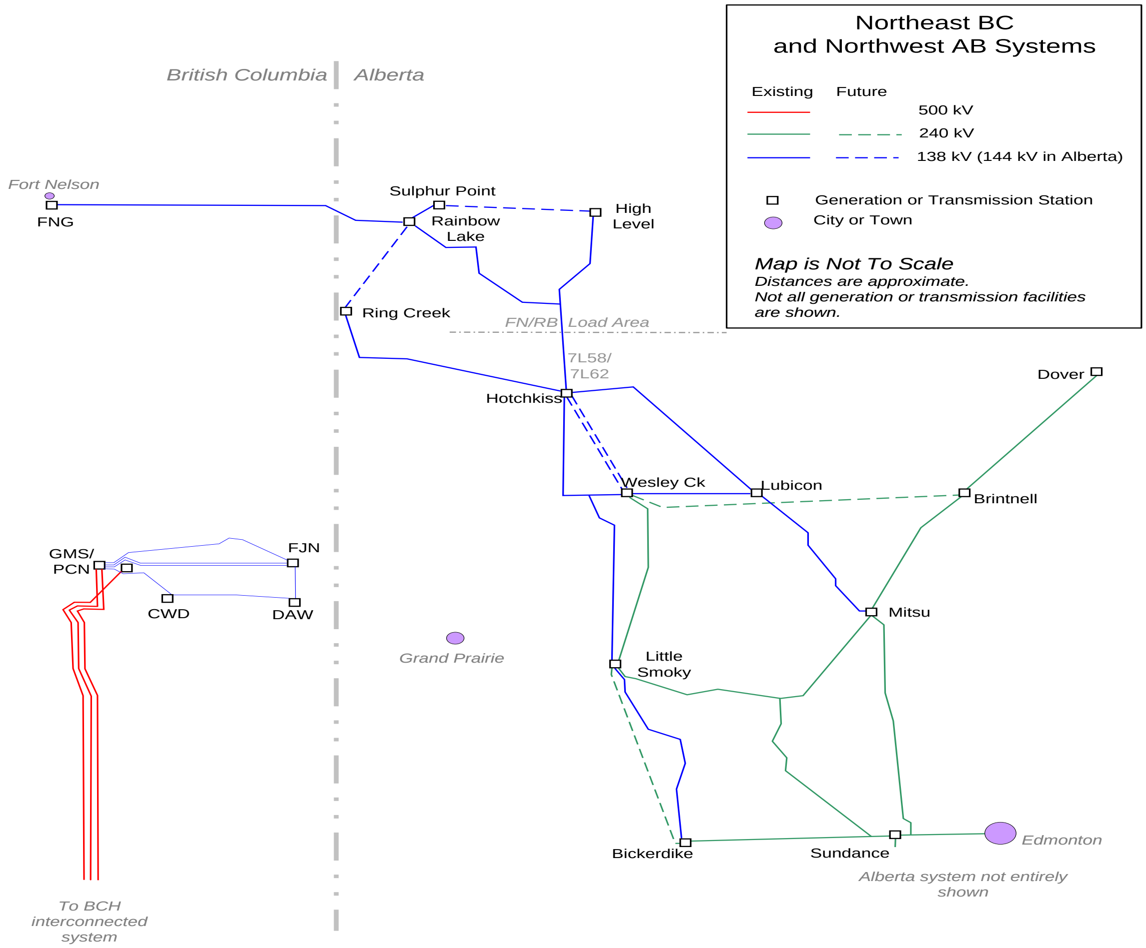
The combination of the FTS and STS agreements provides BC Hydro with back-up service (reliability) and economic benefits through the sale of additional capacity from FNG into the Alberta Power Pool. The AESO requires BC Hydro along with other customers in the Rainbow/Fort Nelson regions to participate in transmission system protection schemes. Because of this requirement, there may be times when BC Hydro must curtail load in B.C. even though the FNG is fully capable of meeting the BC Hydro-based load. However, the result of the AESO's coordinated operation of the Rainbow/Fort Nelson regions is that BC Hydro's customers currently receive more reliable service than would be the case if this coordinated operation did not exist.

[4] Section 302.4 of the ISO rules, Northwest Area Transmission Constraint Management.

[5] Load service is considered "Firm" if it can be supplied with the loss of the most critical single major system element that is usually a transmission line or generating unit. This is often referred to as "N-1" reliability where the "N" represents all of the elements in the system and the "-1" represents the loss of the most critical single element. "N-2" would indicate a situation in which two critical elements were out of service.

The Northeast B.C. and Northwest Alberta transmission lines are shown in Figure 1.

Figure 1 Northeast B.C. and Northwest Alberta Transmission



2.2 Current Supply Situation

2.2.1 BC Hydro Service Obligation and Tariffs in the Fort Nelson Region

BC Hydro has an obligation to serve new customers within its service area who meet the terms and conditions of its electric tariff. The service obligation is qualified by pre-existing capacity or other constraints that could impact BC Hydro's ability to supply service.

Fort Nelson is currently served at Zone I rates and the service is regulated by the BCUC through the B.C. *Utilities Commission Act*.

2.2.2 Alberta Service Obligations and Tariffs

The Fort Nelson region is unique in that it is not directly connected to the rest of the B.C. Interconnected Electric System (**BCIES**). The Fort Nelson region is electrically connected to the Alberta Interconnected Electric System (**AIES**) and is therefore part of the AESO control area.

In Alberta, both transmission service and electricity market services are provided by the AESO; and the AESO is regulated by the Alberta Utilities Commission. The Alberta *Electric Utilities Act* (***EUA***) was amended in 2008, with one result being a modification of the AESO's obligations with respect to planning the transmission system. Prior to the change, the AESO was to plan the transmission system based on the needs of the market participants (of which BC Hydro was one); as modified, the AESO's obligation under the *EUA* is to plan the system capability based on provincial needs.[6]

The FTS is a unique rate provided to BC Hydro. A key distinction between this tariff and the Demand Transmission Service (**DTS**) service provided to customers located in Alberta is the FTS cost is only partially based on "postage stamp" embedded costs. If BC Hydro contracts for more than 38.5 MW, it must pay a component of the FTS that recovers its pro-rata share of upgrade costs to supply future load growth (i.e., any increases above the currently 38.5 MW FTS level) and, should BC Hydro

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[6] Sections 33 and 34 of the Alberta *Electric Utilities Act* state the following:
Transmission system planning

33 The Independent System Operator must forecast the needs of Alberta and develop plans for the transmission system to provide efficient, reliable and non-discriminatory system access service and the timely implementation of required transmission system expansions and enhancements. 2003 cE-5.1 s33;2007 cA-37.2 s82(4)

Alleviation of constraints or other conditions on transmission system

34(1) When the Independent System Operator determines that an expansion or enhancement of the capability of the transmission system is or may be required to meet the needs of Alberta and is in the public interest, the Independent System Operator must prepare and submit to the Commission for approval a needs identification document that …

terminate its FTS agreement, the AESO can recover its “stranded” costs that are attributable to the terminated FTS agreement.[7]

Following its 2008 Long Term Acquisition Plan (**LTAP**), BC Hydro submitted a request for increased transmission service to the AESO. In response, the AESO has communicated its long-term service obligations to BC Hydro above the existing 38.5 MW level, as follows:

- Any transmission service above 75 MW will not be offered
- Any increase in Fort Nelson load above 38.5 MW is considered to exceed the planning threshold for requiring a “wires” solution
- Beyond 2017, only “wires”-based solutions will be offered to meet any increased level beyond the current 38.5 MW
- Lower cost “non-wires” solutions will only be offered on an interim basis and only if BC Hydro commits to a longer term “wires” solution
- The preliminary cost estimate of its proposed wires solution to supply incremental Fort Nelson load (up to 75 MW) is approximately $300 million

2.2.3 Planning Objectives and Reliability Criteria

BC Hydro serves and plans to serve the electricity demand in the Fort Nelson region in the same way it does in the rest of the interconnected system. The distance from the interconnected system and the lack of a direct connection make the task more challenging, but does not change the objective. The main planning objectives are to reliably meet the customer demand in a cost-effective way.

From a reliability perspective, the Fort Nelson area is radially fed from Alberta and has a single generating plant, FNG, that now consists of two generators, the 47 MW FNG G1 that is driven by a gas turbine and the 26 MW FNG G2 that is driven by a

[7] Refer to Section 7(1) of the AESO’s FTS Rate Schedule.

steam turbine. The primary reliability criterion is based on the largest single contingency (or N-1) standard[8], which requires that sufficient resources be available to meet the area load with the single largest element (transmission line to the area or local generation) out of service.

To fully meet this standard, the following conditions would have to be satisfied:

- When the transmission line is out of service, the local generating supply needs to be adequate to supply the full firm (N-1) demand[9]
- When the single contingency occurs that results in the largest net loss of local generating capacity, the aggregate load-serving capability of the remaining generation (if any) and the transmission interconnection to Alberta must be adequate to supply the Firm demand

The N-1 criterion is both (1) a measure of reliability for transmission planning in B.C.[10] and (2) the AESO's regional criterion for providing service to its north-western region including the Fort Nelson area. From the AESO perspective, any time the criterion cannot be met, load must be disconnected from the system. At present, any increment of load that is above the supply capability in the northwestern region of the AIES may have to be curtailed or immediately shed (tripped) when the load in the Fort Nelson/Rainbow area exceeds 130 MW.[11]

The analysis in the IRP assumes that the N-1 criterion must be met on the Alberta side of the border to comply with the AESO requirements.

[8] BC Hydro does not now apply its system-wide capacity reliability criterion (Loss of Load Expectation) of one day in 10 years) or energy reliability criterion on a regional basis.

[9] When full N-1 capability is not available, some customers are served on a curtailable basis where they could be tripped or asked to curtail their load under some system contingencies at high load levels.

[10] While N-1 is a measure of reliability, it is not necessarily met in all cases.

[11] Measured as the sum of the gross generation from FNG and the Rainbow area generators plus the line outflows from AESO station A788S (7L62 and 7L58).

2.2.4 Fort Nelson Peak Demand Load Forecast

BC Hydro's updated 2012 Peak Load Forecast for Fort Nelson identifies load growth from F2012 of an additional 13 MW for the mid forecast and 50 MW for the high load scenario by F2020. Fort Nelson load is expected to grow by 4 MW under the low load scenario. For both the mid forecast and the high scenario, some of the load growth will be fostered by future oil and gas activity which is anticipated to also increase sales to residential and commercial customers connected to the Fort Nelson distribution system.

The drivers for residential, light industrial and commercial customer load forecasts are housing starts and employment forecasts. The forecast for the industrial accounts are developed based on information from BC Hydro's key account managers and industry reports, and incorporate factors such as specific customers' expansion plans.

The Fort Nelson peak demand forecasts are shown in Figure 2 and Table 1 below.

Figure 2 Fort Nelson Peak Demand Load Forecast/Scenarios and Existing Supply Capacity

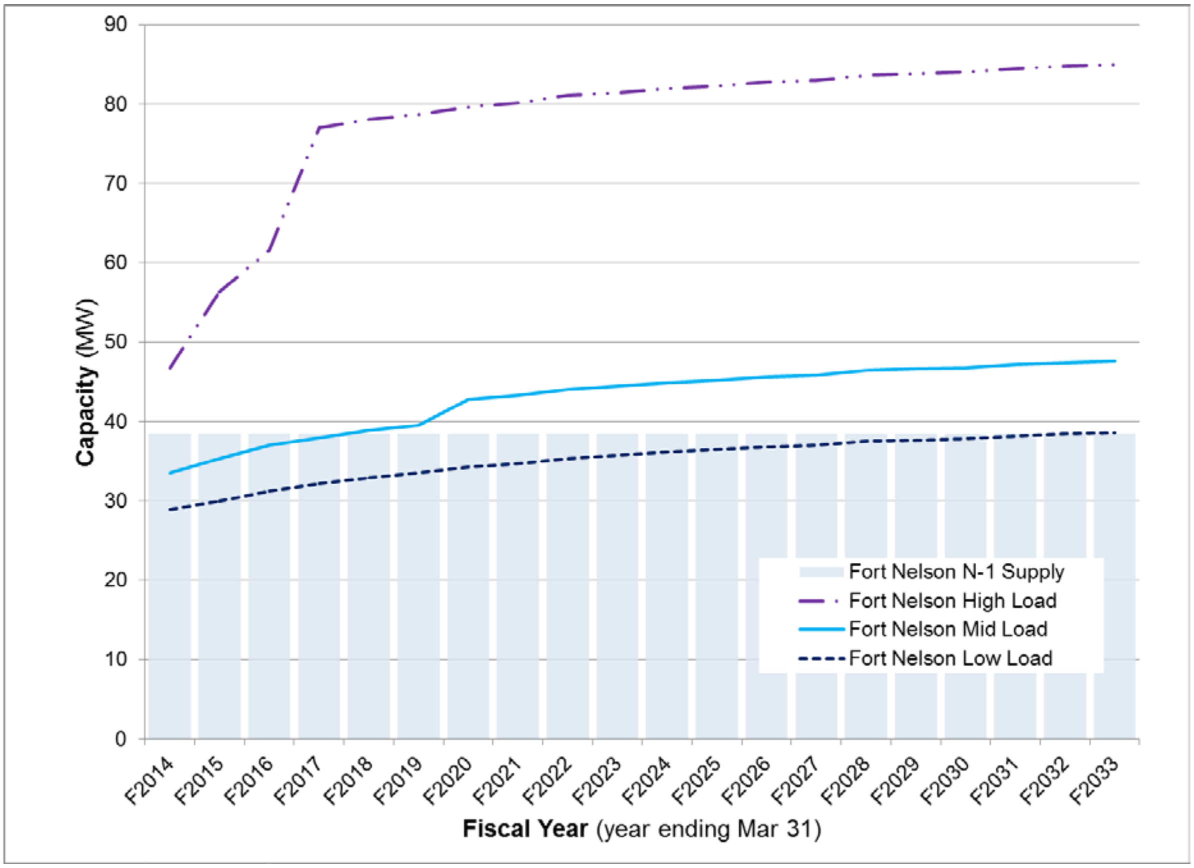


Table 1 Fort Nelson Load Peak Demand (before DSM Savings and including Electricity Rate Impacts)

	Actual	Forecast							
	F12	F13	F14	F15	F20	F25	F30	F35	F40
Mid Forecast (MW)	30.0	30.0	34.0	35.0	43.0	45.0	47.0	48.0	49.0
High Scenario (MW)	30.0	35.0	47.0	56.0	80.0	82.0	84.0	86.0	87.0
Low Scenario (MW)	30.0	26.6	28.9	29.9	34.3	36.4	37.8	39.1	40.2

The mid forecast and high and low scenarios do not include incremental shale gas producer, processing and pipeline loads from electrification within the Horn River Basin. These loads are reflected in various supply scenarios discussed later in this Appendix. The mid forecast is based on most likely estimates of future load.

The high and low scenarios are constructed considering expected changes to industrial loads arising from: (i) existing and future conventional oil and gas customers and; (ii) forestry loads within the region, which have been experiencing operational curtailments in past several years. Also considered are the impacts to residential, commercial and industrial loads within the community of Fort Nelson arising from the production of shale gas in the Horn River Basin.

DSM opportunities were assumed to be minimal for the large incremental industrial loads associated with Fort Nelson and would not impact the expansion projects needed by BC Hydro to serve the load.

2.3 Fort Nelson Supply Considerations

The load in the Fort Nelson region alone (i.e., not including the potential HRB shale gas-related load) is expected to grow from its current level of about 30 MW to between 34 MW (low scenario) and 80 MW (high scenario) by about F2020. In the mid forecast, the load is expected to grow to about 43 MW. The mid forecast and high scenario would exceed the 38.5 MW firm (N-1) capability of the existing resources since the transmission service from the AESO is limited to 38.5 MW and the loss of the 47 MW FNG gas turbine generator (**GTG**) results in the loss of the heat source to the 26 MW FNG steam turbine generator (**STG**), resulting in a 73 MW single contingency.

Based on the current peak demand forecast for the Fort Nelson area (not including the HRB area), by F2020 there will be a capacity shortfall of about 5 MW of firm load-serving capability based on the mid forecast. The shortfall in the high scenario would be about 42 MW by F2020 and Fort Nelson load is expected to remain relatively flat under the low load scenario.

2.3.1 Load / Resource Balance Uncertainties

All three of the load forecast scenarios for the Fort Nelson area (not including the potential HRB shale gas-related loads) were constructed considering expectations of recovery of forestry loads within the region. These forestry loads, namely a "plywood" plant and an "oriented strand board" (**OSB**) plant with about 7 MW of capacity each at full electrical loading, are connected at distribution voltage and have been operating at minimum load levels.

These forestry loads are a significant consideration in determining the need for additional capacity. The mid load forecast includes the potential for one of the forestry plants to return to full operation in F2018. However, market conditions influencing North American demand for forestry products remain inconclusive and significant uncertainty exists as to the timing of one or both plants returning to full operations. If the forestry load does recover as assumed in the mid load forecast, additional capacity would be required by F2018 to serve incremental (above 38.5 MW) load on a firm (N-1) basis. An earlier or later mill restart will advance or delay the need for additional capacity. To date, BC Hydro has not received confirmation of mill re-starts from plant owners.

In addition to forestry load recovery assumptions, the mid load forecast for the Fort Nelson area also considers impacts to residential, commercial and industrial loads within the community of Fort Nelson arising from the production of shale gas in the Horn River Basin. The mid load forecast assumes there is a 50 per cent increase in the small accounts category (equal to about 8.5 MW) by F2020. However, significant uncertainty also exists as to the timing and magnitude of Horn River Basin development and the extent of that development on Fort Nelson load. Should this element of the Fort Nelson load forecast not materialize as expected, it would push out the need for additional capacity to beyond F2018, even if forestry load were to recover as assumed in the mid load forecast.

2.3.1.1 N-0 Supply Considerations

While BC Hydro expects the load growth to be modest over the next five years (F2014-F2018), there are significant uncertainties to the forecast due to potential impacts from Horn River Basin development and/or other load developments such as the restart of currently shut-down forestry mills. In light of these load forecast uncertainties, any decision to add local generating capacity will be contingent on the load forecast becoming more certain.

If one or both of the forestry plants were to recommence full operations during F2014-F2015 planning horizon, BC Hydro would be prepared to offer service on a curtailable (N-0) basis, until such time as provisions are made to procure and/or build additional capacity to serve “returning” or incremental load on a firm basis.

2.3.1.2 N-1 Supply Considerations

As noted in section 2.2.3, the reliability requirements for serving the Fort Nelson load in the long term would normally be assessed against the N-1 capacity criterion. By ensuring that it has adequate interconnection and supply resources to meet this capacity reliability criterion, BC Hydro would always be able to reliably satisfy the Fort Nelson energy requirements. The following section provides a planning level assessment of capacity options for providing N-1 service to Fort Nelson, if and when the need arises.

2.3.2 Fort Nelson Local Supply Options

In cases that do not include BC Hydro supplying electricity to the Horn River Basin, BC Hydro assessed two options for meeting the projected Fort Nelson N-1 capacity shortfall: (1) Increase the level of transmission service to the area; and (2) adding local generating capacity. The results of the analysis of these two options were then used to inform BC Hydro’s near-term commitment decision for Fort Nelson.

2.3.2.1 Increased Transmission Service from Alberta

Upgrades to the transmission system serving the Alberta Northwest region will be required if BC Hydro asks the AESO to increase the FTS level.

2.3.2.2 BCIES

Given Fort Nelson's relatively modest load growth, BC Hydro does not consider supplying just Fort Nelson load from BC Hydro's integrated system via high voltage transmission line to be an economically feasible option. However, this alternative is considered within a broader Fort Nelson/HRB supply strategy.

2.3.2.3 Local Gas-Fired Generating Capacity

The primary requirement for new generating capacity will be for capacity reliability, or reserve, purposes; or for load growth near the high scenario. The former could be met with peaking capacity that is only required when FNG is not available, while the load growth for the latter would likely be tied to significant HRB development which would increase the opportunities for Fort Nelson/HRB integration.

As a result, simple cycle gas turbines (**SCGT**s) or diesel engines would probably be the best alternatives, taking advantage of the relatively lower capital costs, footprints and lead times, at the expense of operating costs.

The analysis in this IRP tests the LMS100 gas turbine, a machine that is included in BC Hydro's Resource Options Database. It is relatively high efficiency in simple cycle and when combined with the existing resources, it would be sufficient to meet the projected high scenario peak demand.

2.3.2.4 Clean or Renewable Resources

Using local clean and renewable resources backed up by local gas-fired generation capacity is not considered a feasible supply strategy for serving just Fort Nelson load, primarily because the Fort Nelson supply situation is a capacity rather than energy issue.

3 Natural Gas Resource Development in the HRB

With respect to the Horn River Basin, natural gas development industry activity in recent years has not translated into applications for service. However, issues such as climate change and greenhouse gas (**GHG**) legislation have created opportunities to use electricity as a means of reducing GHGs that result from the HRB natural gas production, processing and sales. The raw natural gas in the HRB has a relatively high concentration (12 per cent) of carbon dioxide (**CO_2**).[12] This formation CO_2 is currently removed from the natural gas during processing, and vented to the atmosphere.

There are generally two opportunities to reduce GHG that is vented to the atmosphere in the HRB:

- To capture and sequester the formation CO_2 in deep underground storage
- To replace relatively low efficiency natural gas work sources, such as compression drives or local generators, with clean electricity or with higher efficiency CCGTs or co-generation (generators that make use of both the electricity and heat)

However, the opportunities come at a cost, particularly in remote regions such as the HRB. These costs are economic – increased cost of infrastructure; flexibility – time to develop new infrastructure; and commercial – establishing and managing commercial arrangements between multiple entities. In turn, these costs may impact the competitiveness of the gas supply from the HRB, leading to a number of challenges to supplying electricity to the region, including:

- Uncertainty of HRB development and economic life; and associated electricity requirements
- Competitiveness of the HRB region (including individual processing plants)
- Distance and timing of electricity service to specific facilities
- Climate change policy considerations

[12] Most natural gas reserves do not contain such levels of CO_2; for example, raw natural gas in the Montney Basin contains less than 2 per cent CO_2, a level that is within acceptable maximums for sales gas, thus not requiring extraction and venting.

The analysis framework for the Fort Nelson/HRB regions in this IRP was designed to evaluate these uncertainties. The analysis has a very long-term horizon (through 2060), to attempt to capture the opportunities and risks of serving the HRB through the forecast life of the gas reserves. It starts from three scenarios of annual natural gas production through to 2060, and calculates the equipment and energy required to provide the work energy to extract, compress, process and ship the natural gas that is produced. Strategies with respect to work energy supply types are as follows:

- industry continuing as business as usual, with no electric service from BC Hydro
- BC Hydro supplying electricity produced by clean resources or by natural-gas fired resources
- BC Hydro providing transmission network services within the HRB

This section of the IRP addresses the following key issues regarding the HRB:

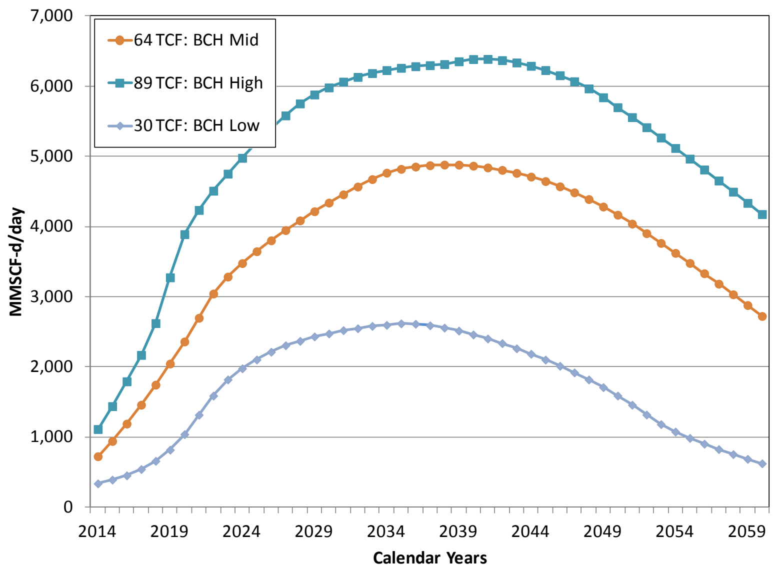
- The amount of CO_2 that is produced in the HRB under various natural gas production and energy supply scenarios
- The electricity supply costs under various gas production and energy supply scenarios
- The effect of electricity service to the HRB on BC Hydro's 93 per cent clean energy objective
- The potential for additional benefits related to electricity supply to the HRB, such as access to new clean supply resources

3.1 Natural Gas Production Scenarios

BC Hydro developed three natural gas production scenarios for the HRB as part of its load forecasting process. These scenarios are indicative of the range of uncertainty that exists with respect to the development of the region.

BC Hydro understands that the economics for HRB development are challenging relative to other sources of natural gas in the world, but that industry continues to advance HRB projects with the expectation that it will be economically developed.

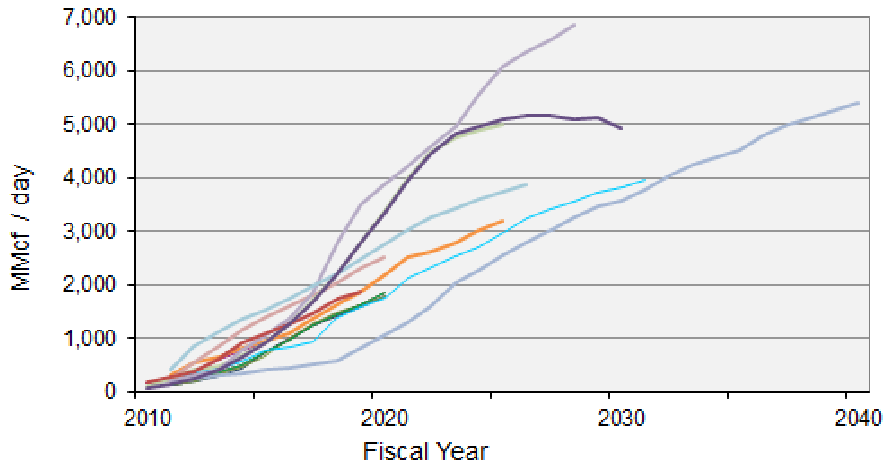
Figure 3 BC Hydro's HRB Natural Gas Production Scenarios



The three natural gas production scenarios generally encompass and reflect the forecasts that BC Hydro has received from third parties that make forecasts for the region. These forecasts are presented in Figure 4.[13]

[13] BC Hydro receives some of its forecasts on a fee-for-service basis. To protect their proprietary nature, the sources of the forecasts presented in the figure are not attributed.

Figure 4 HRB Shale Gas Production Forecasts



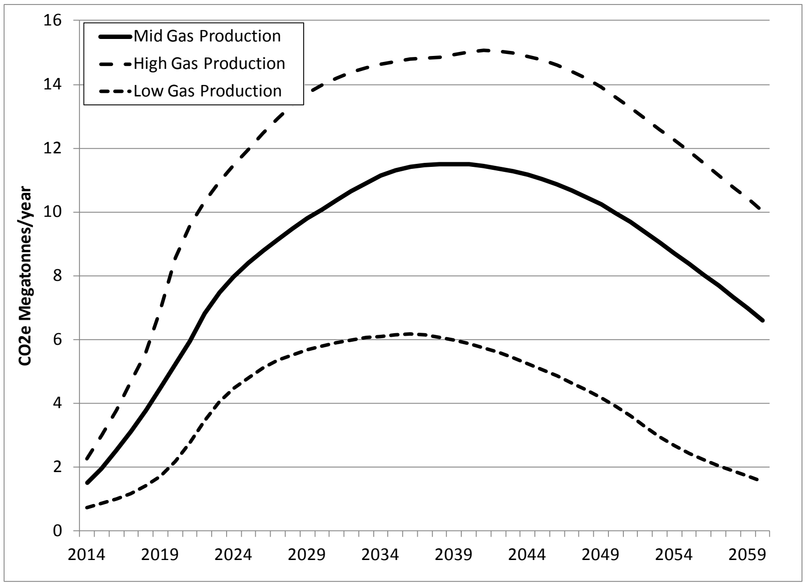
The portfolio analysis for the Fort Nelson/HRB region considers all three scenarios.

3.2 Associated Formation CO_2 Production

Natural gas produced in the HRB contains approximately 12 per cent CO_2 by volume. The associated CO_2 production is shown in Figure 5 for each of the above natural gas production scenarios.

As compared to the target GHG reduction in the *Greenhouse Gas Target Reduction Act* of 46 mega tonnes in 2020, the potential GHGs from the HRB, alone, would have a material impact.

Figure 5 Formation CO_2 Associated with Natural Gas Production Scenarios



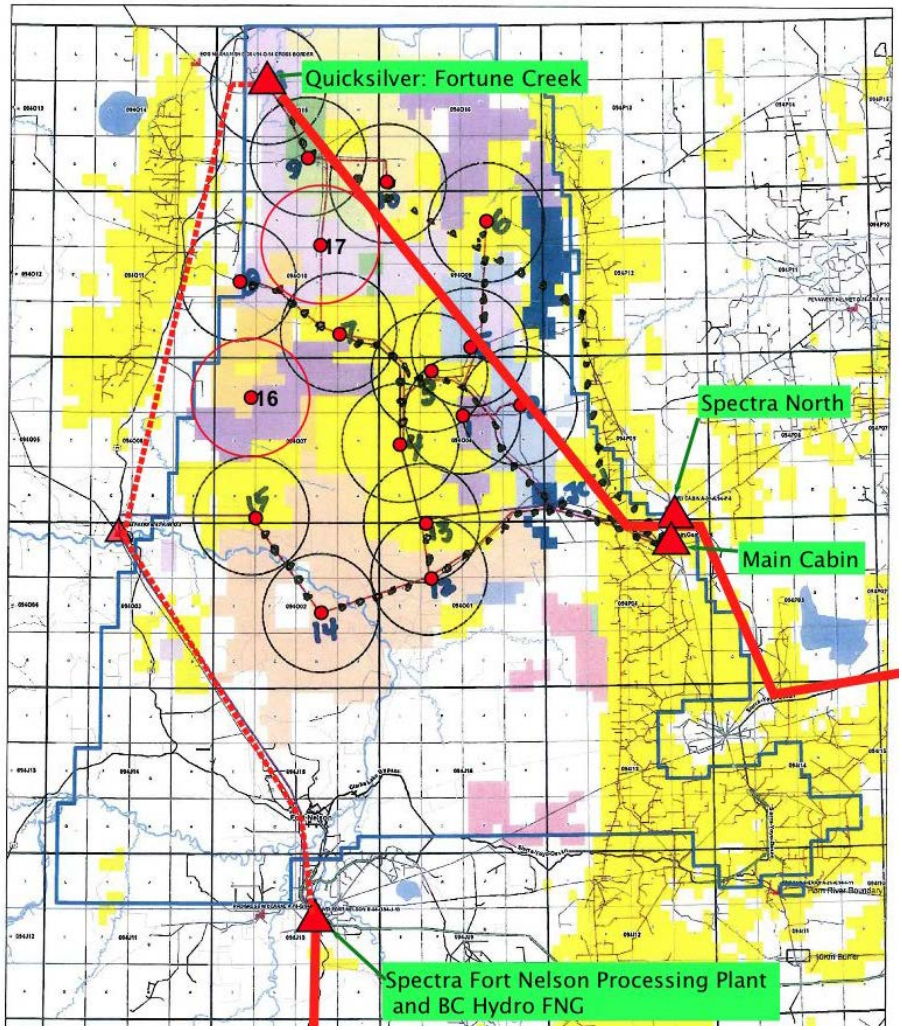
3.3 Industry Facilities

Development of the HRB natural gas potential will include, at a minimum, raw gas treatment (**RGT**) facilities, natural gas processing plants, and sales gas pipelines. It may also include facilities associated with sequestering the formation CO_2.

Some facilities have already been committed or are in service, but these resources are not sufficient to meet the requirements of the mid and high natural gas production scenarios, and may not be enough for the low scenario. As a result, BC Hydro made certain assumptions with respect to the build-out of facilities.

A description of the assumptions is provided in the following subsections. Figure 6 provides a pictorial reference. The red triangles are the actual or assumed locations of processing plants; and the small red circles are the locations of RGTs, the red lines are sales gas pipelines.

Figure 6 Industry Facilities Assumed in IRP Analysis



3.3.1 Processing Plants

BC Hydro has assumed up to five processing plants in the analysis, depending on the level of natural gas production. The processing plants are Spectra Fort Nelson located beside the FNG; Cabin (Enbridge); Spectra North; Quicksilver; and a fifth processing plant, assumed to be on the west side of the HRB.

Capacity is assumed to be added in increments of 250 or 400 MMscfd/day at Cabin, Spectra North, Quicksilver and the fifth processing plant, as required for the production scenario. Each existing and planned processing plant is assumed to be self-sufficient for electricity and heat requirements, unless sources of electricity and heat are available from BC Hydro or a third party.

Processing plants are each assumed to be stand-alone business units competing to process natural gas. For any one scenario, total raw natural gas volumes being processed and shipped in a given year are assumed to be prorated across the processing plant capacity in service.

3.3.2 Capture and Sequester Formation CO_2

For any scenarios that include the capture and sequestration of formation CO_2, the compression facilities for the CO_2 are assumed to be situated at the processing plant where the CO_2 was extracted from the raw natural gas. In these scenarios, sequestration is assumed to start in 2018 and linearly ramps up to full sequestration by 2022.

3.3.3 Raw Gas Treatment Facilities

RGT facilities are decentralized facilities that gather raw natural gas from nearby well platforms. Several RGT facilities exist and others are expected to be developed. Figure 6 identifies 17 locations that BC Hydro has assumed for the analysis.

In the analysis, the number of RGT facilities depends on the level of natural gas production. Production from each RGT facility is assumed to be proportionate to the total volume of natural gas being produced.

Of the total compression load for the sales gas, 85 to 90 per cent is assumed to be located at the RGT facilities; the remaining compression is located at the processing plants.

3.3.4 Sales Gas Pipelines

Two main pipeline systems are assumed to be used – namely, the existing Spectra pipeline running from Fort Nelson to the Lower Mainland and the TransCanada/NGTL pipeline that is currently under construction.

Together, the existing and committed capacity of these two pipelines is not sufficient to meet the mid or high natural gas scenarios. It is assumed for the analysis that all new pipeline capacity will have the pressure characteristics of the NGTL pipeline.

4 Electricity Supply Assumptions

4.1 Energy Supply

The IRP analytical approach for addressing the combined Fort Nelson/HRB region electricity supply requirements assumed four general types of resources are available to BC Hydro: B.C. Clean or Renewable Electricity (in this report, generally called clean electricity); natural gas-fired co-generation; stand-alone CCGTs; and stand-alone SCGTs.

The clean electricity supply is represented by the resources that are assumed to be available more generally in the IRP. A new resource stack was developed with the System Optimizer from a simulation with the mid load scenario on the integrated system plus the high electric load scenario for the Fort Nelson/HRB. From this, cost and capability characteristics were identified for the Fort Nelson/HRB analysis.

The co-generation supply is assumed to be situated at either one or two processing plants. As the name suggests, the co-generation provides both electricity and heat; the electricity is fed into the transmission network to serve BC Hydro loads, while the heat is supplied to the host processing plant. The amount of heat supplied is the lesser of the heat available from the co-generator and the heat required at that host processing plant in any study year. The co-generators were assumed to be either GE Frame 6FA machines in a three-on-one configuration; or GE LM6000 machines with no heat recovery steam unit.

For any CCGT scenarios, the CCGTs are assumed to be situated at FNG. All potential heat recovery is used within the CCGT, with no heat sales to host processing plants (i.e., these are not co-generation plants). The CCGTs analyzed were assumed to be a clone of the FNG units, based on the GE LM6000.

SCGTs are assumed to be used in two alternative supply strategies: the first is as a backup to FNG, for those strategies where Fort Nelson is not interconnected to the HRB or the integrated system; and, the second is as a firming resource to backup local wind resources in strategies where BC Hydro relies on clean or renewable electricity without interconnecting to the integrated system. In both situations, the SCGT analyzed was the GE LMS100.

4.2 Network Transmission

Network transmission will include segments of the North East Transmission Line (**NETL**), as required. Segments are assumed to be: (1) Peace River to North Peace River (**NPR**), which is described as Peace Canyon (**PCN**) to NPR; (2) NPR to FNG; and (3) FNG to HRB (Cabin processing plant).

Transmission costs used in the analysis are based on the NETL studies prepared by SNC Lavalin for BC Hydro in 2012. The studies included the transmission costs for NETL, along with the transmission network that would be required within the HRB to serve processing plants and RGT facilities. In these studies, the NETL was assumed to be at 500 kV.

For electricity supply strategies that do not include connection to the BC Hydro integrated system (i.e., PCN to NPR), there is a one-time network setup cost of $20 million that is assumed to provide any necessary communications and control costs, stability control, and reactive support.

The transmission network segments described above are assumed to be owned and operated by BC Hydro.

4.3 HRB Regional Transmission

Regional transmission between processing plants and RGT facilities, where required, was set at 230 kV or 138 kV, depending on the individual loads being served. The regional transmission network within the HRB is assumed to be owned and operated by BC Hydro.

5 BC Hydro Supply Strategies Analyzed

5.1 Electric Supply Strategy Alternatives

The following strategies were assessed as part of this IRP:

Table 2 Summary of Fort Nelson/HRB Electricity Supply Strategies

Supply Alternative	Strategy Description
Alternative 1 BC Hydro Integrated System	Supply Fort Nelson/HRB with clean energy or renewable energy from the BC Hydro integrated system. With this strategy; a new transmission line would be built from Peace Region to Fort Nelson and then up to the HRB. This would connect Fort Nelson and the HRB to BC Hydro's existing integrated system.
Alternative 2A Regional-Based: One Fort Nelson/HRB Network	With this strategy, the two regions of Fort Nelson and HRB would be connected via a new transmission line. Generation could be developed in one area to service both regions or plants could be dispersed in both regions. Various gas-fired generation options were examined, along with the option of combing local clean and gas-fired generation resources. The different options considered as part of this strategy include: **2A1:** Supply with gas co-generation (1) One co-generation plant in Fort Nelson (2) Two co-generation plants in Fort Nelson and HRB **2A2:** Supply with CCGT in Fort Nelson **2A3:** Supply with local clean energy (wind) and backed by SCGT in Fort Nelson.
Alternative 2B Regional-Based: HRB alone	With this strategy, both regions are supplied separately and from within their own region. A gas-fired cogeneration plant would service the HRB, and a new SCGT would service Fort Nelson or increased service from Alberta. The different options considered as part of this strategy include: **2B:** Supply HRB as a separate network with a gas co-generation plant and supply Fort Nelson with either: (1) a new SCGT in Fort Nelson, or (2) increased transmission service from Alberta.
Alternative 3 Supply Fort Nelson alone; HRB producers self-supply	With this strategy, the HRB region is not serviced by BC Hydro but instead companies would self-supply their energy requirements. A new SCGT would service Fort Nelson or increased service from Alberta. The different options considered as part of this strategy include: **3:** No service to HRB; supply Fort Nelson: (1) a new SCGT in Fort Nelson (2) increased transmission service from Alberta

The following sections describe each of the supply strategies, starting with a description of a strategy where BC Hydro only provides service to Fort Nelson, followed with strategies that involve varying levels of BC Hydro-supplied electrification of the HRB.

5.2 Supply Fort Nelson Only

This strategy (referenced as “Alternative 3”) tests the alternative where there is no new electric network development, or that any new networks are developed independently of BC Hydro involvement. Under this assumption, BC Hydro would continue to serve the current Fort Nelson network, and would not take on any customer responsibilities in the HRB. The AESO FTS service is assumed to be retained.

BC Hydro currently does not have enough supply resources to serve its expected load requirements on a N-1 reliability basis. In this strategy, two general alternatives described in section 2.3 are tested to increment the supply capacity to meet the Fort Nelson load on a N-1 basis. The alternatives are: adding a SCGT or other generation at FNG (referenced as “Alternative 3(1)”); or, increasing and extending the commitment for FTS service from Alberta (referenced as “Alternative 3(2)”).The results of this analysis inform BC Hydro’s near-term strategy with respect to committing to new supply for Fort Nelson, or deferring any commitment until there is more certainty as to the future load levels.

Real-time to short-term load/resource balancing[14] is managed through dispatch of FNG in conjunction with sales (purchases) to (from) Alberta; with the interconnection used for firm purchases when FNG cannot meet the local load, and exports when FNG is operating.[15]

[14] Includes the timeframe until new planning resources could be installed, if required.

[15] While net exports at the operational level have value to BC Hydro, such value is second order compared to long-term load resource costing. The modelling cannot capture that level of detail, but can be considered subjectively.

5.3 Electrification Penetration Levels

Extending electric service to the HRB does not, in itself, ensure that all loads will be electrified. Some loads may be too remote to be electrified, other loads may not be economic to convert from natural gas drives to electric drives, and others may be too near the end of their economic life. In the IRP analysis, the assumption is that all processing plant load (in the region electrified) that can be electrified, is electrified; and that all compression for CO_2 sequestration (irrespective of where it is located) is electrified. The RGTs are expected to be more decentralized; and their electrification was tested using the electrification pick-up rates set out in Table 3.

Table 3 Electrification Penetration Levels for RGT Facilities

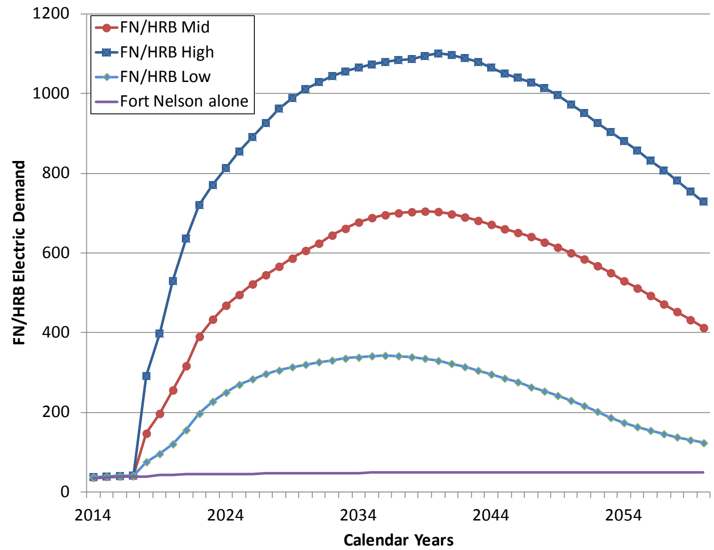
Electrification Intensity	Pick-up of Existing Loads (%)	Pick-up of New Loads (%)
Low	25	50
Mid	35	75
High	75	100

For example, in the low electrification case, 25 per cent of any existing compression load at the RGT facilities will be converted to electric drives in the year that electricity is available in HRB; and 50 per cent of any future electrical growth will be electrified.

No wellhead load is assumed to be electrified.

For the IRP analysis, three HRB electrification load growth scenarios (high, mid, and low), along with the Fort Nelson mid load growth forecast, were used. These scenarios are reflected in Figure 7.

Figure 7 Fort Nelson/HRB Peak Demand Scenarios



5.4 System-Based Clean or Renewable Energy Supply Strategy

This strategy (referenced as "Alternative 1") tests the alternative of BC Hydro interconnecting the Fort Nelson/HRB regions to the integrated system with a Northeast Transmission Line (NETL) and supplying the full Fort Nelson/HRB region with system clean or renewable electricity.

All segments of the NETL from PCN to HRB are assumed to be developed and placed in service by 2018. System clean or renewable electricity, and associated capacity, is assumed to be acquired on the BC Hydro integrated system and delivered to the Fort Nelson/HRB.

Within the broader IRP, there is analysis of the incremental value to BC Hydro of having the NPR node connected, which opens up a large potential for additional wind supply resources. The estimated incremental value (benefit) of having the NPR node is $157 million, and possibly more. In this analysis, a NPV[16] benefit of

[16] NPV = Net Present Value.

$150 million has been assumed for scenarios where the full NETL is installed in 2018.

The AESO FTS service is assumed to be terminated; and all regional transmission and sub-transmission is assumed to be developed.

Under this strategy, all load/resource balancing would be managed on the integrated system, as part of BC Hydro's normal course of operational control. FNG would be used as standby generation.

5.5 Regional-Based Supply Strategies (One Transmission Network)

In these strategies, there is one transmission network interconnecting Fort Nelson and the HRB with energy supplied regionally. This FN/HRB network is not interconnected to the BCIES.

5.5.1 Co-generation at Processing Plants Strategy

This strategy (referenced as "Alternative 2A1") tests the alternative of not integrating the Fort Nelson/HRB to the integrated system. The new electricity supply source is assumed to be co-generation sited at one or two of the processing plants. Electricity that is generated is acquired by BC Hydro and served to customers; while waste heat is used at the host processing plant.

This strategy has two sub-strategies:

(i) one co-generating plant at FNG supplying heat to Spectra Fort Nelson (referenced as "Alternative 2A1(1)")

(ii) two co-generating plants, one at FNG and the other at Cabin, with any required co-generating capacity being divided between the two plants (referenced as "Alternative 2A1(2)")

The IRP analysis evaluates the costs and benefits of various network and supply configurations to test the relative efficiencies, methods to maximize the efficiencies, and risks to obtaining the intended efficiency levels. These tests are not intended to be an analysis of any specific commercial arrangements.

The network transmission from FNG to HRB, and all HRB regional transmission are assumed to be developed. The AESO FTS service is assumed to be retained for load/frequency support.

Real-time to short-term load/resource balancing would be managed within the Fort Nelson/HRB region, absorbing any imbalances with the installed co-generation. The interconnection to Alberta would be available in a supporting role.

5.5.2 CCGT Strategy

This strategy (referenced as “Alternative 2A2”) tests the alternative of leaving the Fort Nelson/HRB region as a separate network (not connected to the integrated system), and supplying the total Fort Nelson/HRB region with electricity from additional CCGT capacity at FNG. The strategy can identify costs of the relatively efficient combined cycle power production that can be used in comparison with the more commercially complex (but potentially more efficient) co-generation alternatives.

The network transmission from FNG to HRB, and all HRB regional transmission are assumed to be developed. The AESO FTS service is assumed to be retained for load/frequency support.

Real-time to short-term load/resource balancing would be managed within the Fort Nelson/HRB region, absorbing any imbalances with the installed CCGTs. The interconnection to Alberta would be available in a supporting role.

5.5.3 Local Clean or Renewable Electricity Strategy

This strategy (referenced as “Alternative 2A3”) tests the alternative of leaving the Fort Nelson/HRB region as a separate network (not connected to the integrated system), and supplying the total Fort Nelson/HRB region with clean or renewable electricity (wind resources) that is backed up with SCGTs.

Based on past studies and the resource database of the IRP, the lowest cost clean or renewable electricity option available to the Fort Nelson/HRB region is the wind potential in the NPR. The strategy is based on developing the two segments of NETL from NPR to HRB, acquiring the wind resources, and backing up those resources with SCGTs sited at FNG.

The AESO FTS service is assumed to be retained for load/frequency support; and all HRB regional transmission is assumed to be developed.

Real-time to short-term load/resource balancing would be managed within the FN/HRB region, absorbing any imbalances with the installed SCGTs. The interconnection to Alberta would be available in a supporting role.

5.6 Regional-Based Supply Strategy (Two Transmission Networks)

This strategy (referenced as “Alternative 2B”) tests the alternative of having two separate transmission networks: the existing Fort Nelson network, continuing in its current configuration; and a new HRB network, operating isolated from other networks, with all co-generation located at Cabin.

Supply to the Fort Nelson network considers two alternatives:

- adding a SCGT or other generation at FNG (referenced as “Alternative 2B(1)”)
- increasing and extending the commitment for FTS service from Alberta (referenced as “Alternative 2B(2)”)

The regional transmission and sub-transmission network within the HRB is assumed to be developed and operated as a separate network. Real-time to short-term load/resource balancing would be managed within the Fort Nelson/HRB region, with all imbalances being absorbed by the installed co-generation.

The Fort Nelson network would continue to operate in its current configuration, interconnected to Alberta; with the AESO FTS service assumed to be retained for firm back-up and load/frequency support. Spectra Fort Nelson would continue to choose to operate as an isolated facility, not connected to the BC Hydro network.

Real-time to short-term load/resource balancing on the Fort Nelson network would continue to be managed through dispatch of FNG in conjunction with sales (purchases) to (from) Alberta; with the interconnection used for firm purchases when FNG cannot meet the local load, and exports when FNG is operating.

6 Results

6.1 Introduction

The modelling for the Fort Nelson/HRB analysis is done over a very long time period, effectively 43 years from the assumed 2018 in-service date of new transmission needed to connect Fort Nelson/HRB to BC Hydro's integrated system. This approach allows for the testing of whether facilities, such as transmission lines, may become stranded, and if the effect, when considered today, is material.

It also provides insight into how the overall system might operate, and issues that may arise. That is not to say that any one issue will arise, rather that any identified issues may need more attention before any decisions to electrify the region are taken. The HRB will be a large area, with a relatively small number of electricity or host heat customers, which will lead to some relatively challenging commercial and long-term risk allocation decision requirements. The first step is two-fold: (1) understanding the size of the opportunity; and (2), identifying the questions that need addressing.

6.1.1 Processing Plant Life-Cycle Operations

The HRB analysis includes an assumption that the raw natural gas processing would be done at up to five locations, and that the processing plants would be expanded as the amount of natural gas requiring processing increases. Conversely, later in the life cycle, plant capacity is assumed to be mothballed or decommissioned, as natural gas volumes decline.

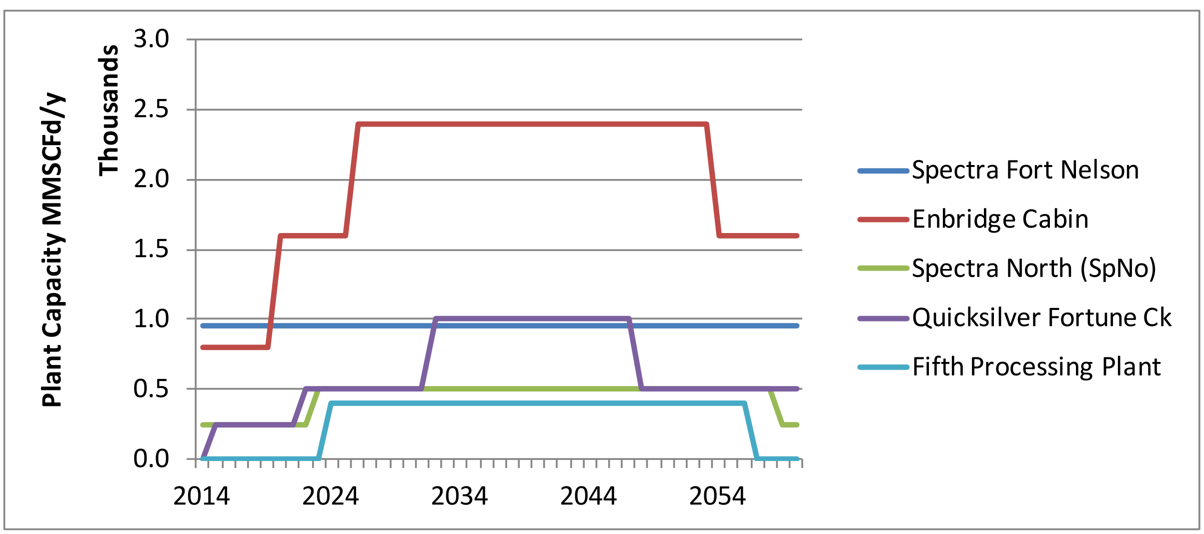
Over the life of the HRB natural gas field, there could be some expectation that production volumes could increase or decrease, as economic or physical conditions change. Such changes would also lead to processing plant capacity being under-utilized or, conversely, that the processing capacity becomes a constraint.

The above conditions, if or when they arise, will impact any one processing plant both from a macro level for the HRB, and from an individual plant's relative competitiveness. BC Hydro cannot predict these events, or their effects. However, decisions today can be made understanding that such possibilities may occur.

The following analysis looks at one example of processing plant capacity and capacity factor over the study term. The example is based on the mid natural gas production scenario, which peaks at 4,800 MMcfd/day in 2039.

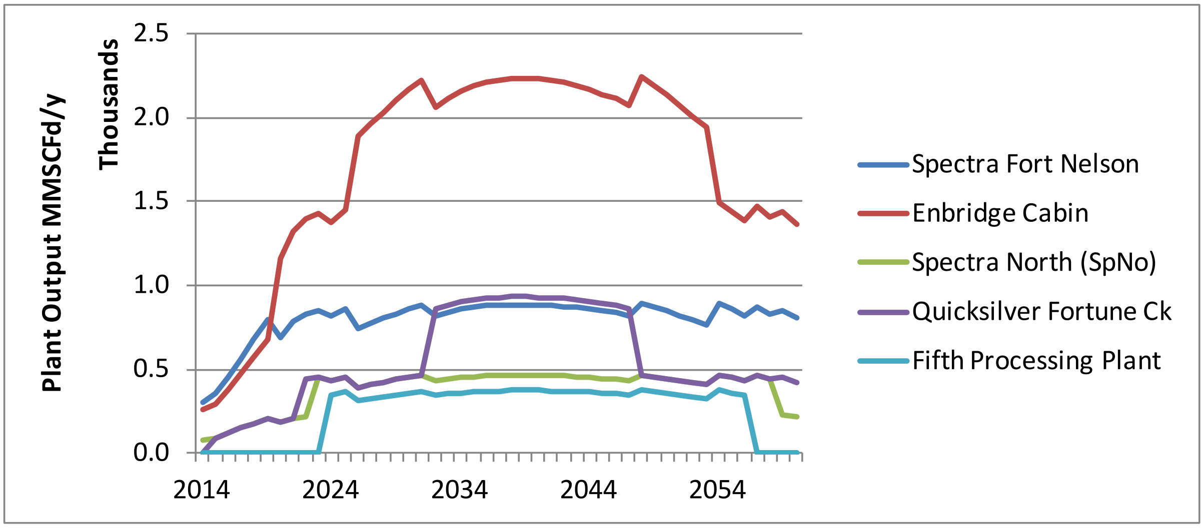
Modelled processing capacity, in that scenario, is as presented in Figure 8.

Figure 8 HRB Raw Natural Gas Processing Plant Capacity



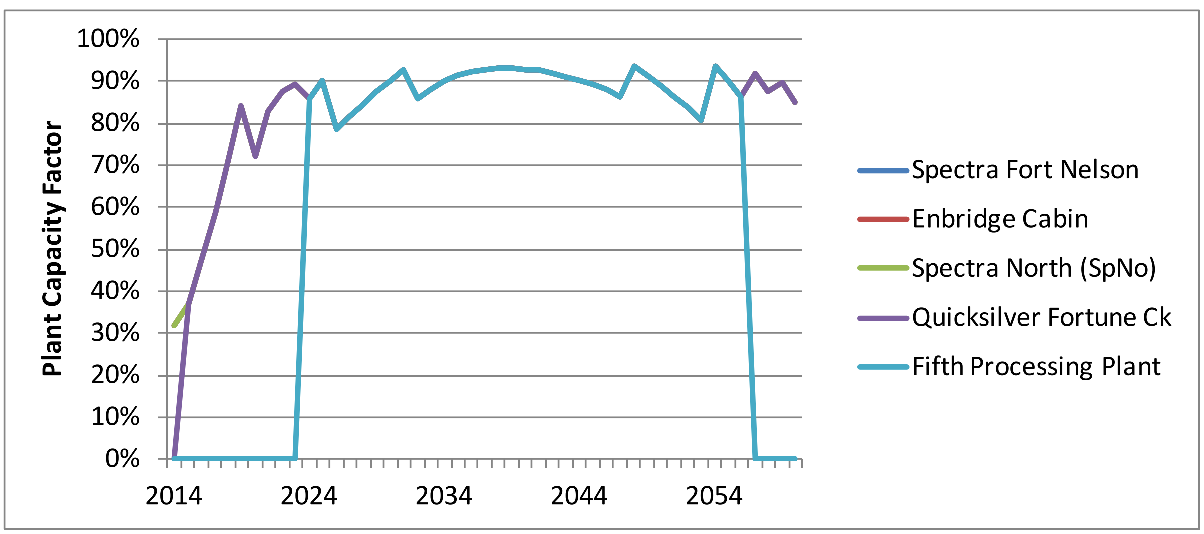
With this capacity, and the overall natural gas processing level for the HRB, the individual plant output, assuming all are equally loaded (equally competitive), would be as shown in Figure 9.

Figure 9 HRB Processing Plant Annual Throughput



This leads to the processing plant capacity factors shown in Figure 10.

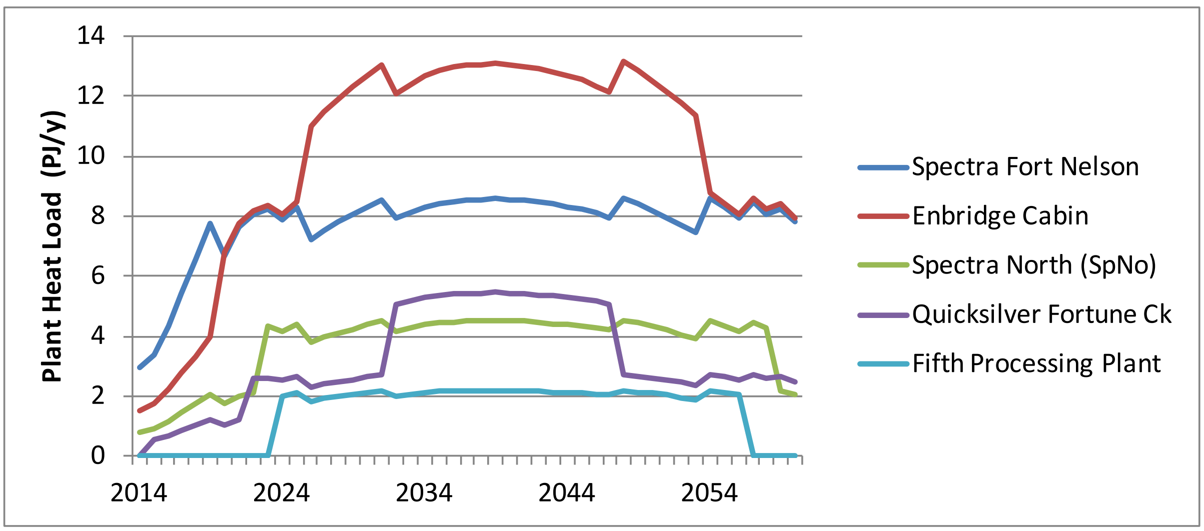
Figure 10 Processing Plant Capacity Factor



Ultimately, processing plant capacity build-out will not follow the exact pattern shown above; rather, it will be based on individual competitive companies making decisions as to their ability to construct and operate competitive facilities as time proceeds. Similarly, processing plant capacity factors will not all be equal, and may not be as high as indicated in Figure 10. Similar graphics under the low natural gas production scenario, for example, show much less capacity and lower capacity factors.

Finally heat requirements at each processing plant will be dependent on the capacity of that plant, and the actual volume throughput at any point in time. Figure 11 presents the assumed heat load at each plant based on the estimated unit heat requirements at each plant, and the annual average processing throughput in this scenario.

Figure 11 Processing Plant Heat Load



BC Hydro's potential electric supply requirements would depend on the electrified load at the combined processing plant facilities, the electrified RGT load, and possible sequestration compression load. Electric market risk or uncertainty will be based on the combined electrified load in the HRB and current domestic customers.

Network and regional transmission characteristics will create certain opportunities or restrictions with respect to the ongoing balancing of load supply and demand:

- In the system-based clean or renewable energy supply strategy (Alternative 1), any imbalances in load and generation can be made up from the BC Hydro integrated system, including interconnection to the U.S. or Alberta
- In the case of the Fort Nelson/HRB supply strategies (Alternatives 2A), there is a small amount of room to manage imbalances through the interconnection to Alberta over the FNG-Rainbow Lake transmission line. However, such usage would scavenge the current use of the line to manage similar imbalances, with the result being that it is not clear if there would be a net benefit or net cost of such change in usage. Independently, transactions with Alberta are on a non-firm basis, and any decision to implement a strategy that would depend on increased volatility of flows to/from Alberta would have to recognize the possibility of the AESO implementing more restrictive rules.
- In the case of the HRB alone supply strategy (Alternative 2B), there would be two separate transmission networks:
  - The new HRB regional transmission system would have no interconnection to manage imbalances, and would have to be self-sufficient
  - The existing Fort Nelson network with interconnection to the Alberta system would continue to operate as currently operated

In addition, for any co-generation strategy, the heat load for any one co-generation plant to feed will be based on the heat requirements at that plant at any point in time. Imbalances between heat and electrical requirements at any point in time would result in that co-generation plant operating at reduced efficiency.

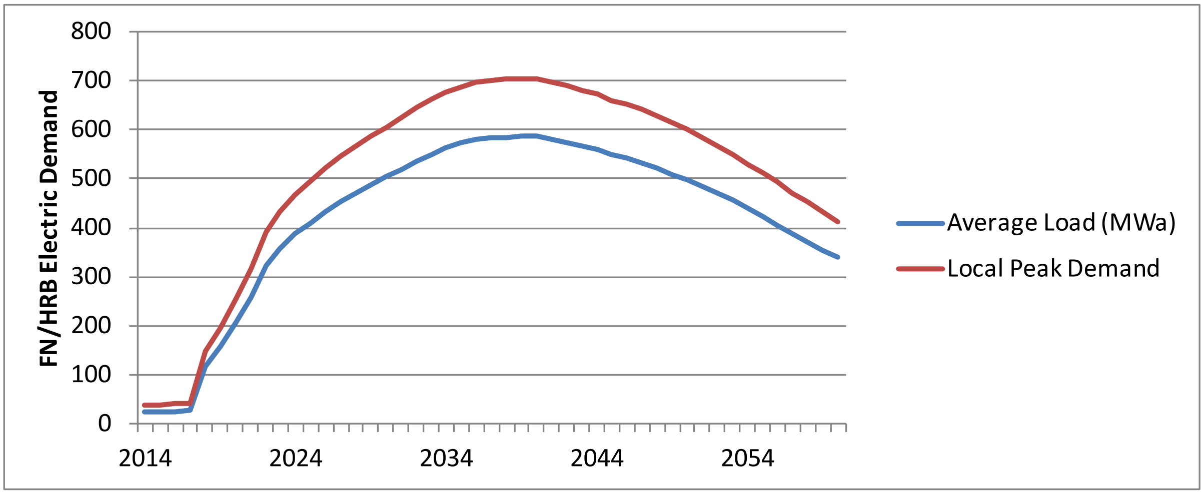
The results presented in the remainder of this section will reflect the combined effect of these factors.

6.1.2 BC Hydro Load Served

The BC Hydro load served, if electrification proceeded, for the above mid production/mid electrification scenario would be as presented in Figure 12. The Fort

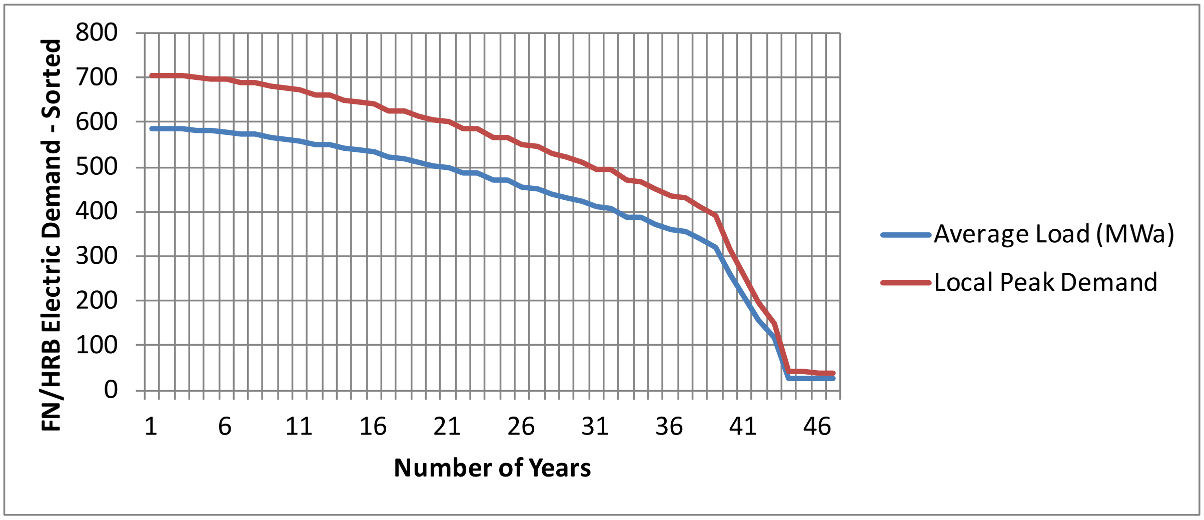
Nelson/HRB customer demand ramps up relatively quickly once electricity is available to the HRB in this scenario. Through the 2030s the load continues to grow, and then decline in the last half of the assumed life of the gas field.

Figure 12 BC Hydro Local Peak and Average Demand for Fort Nelson/HRB



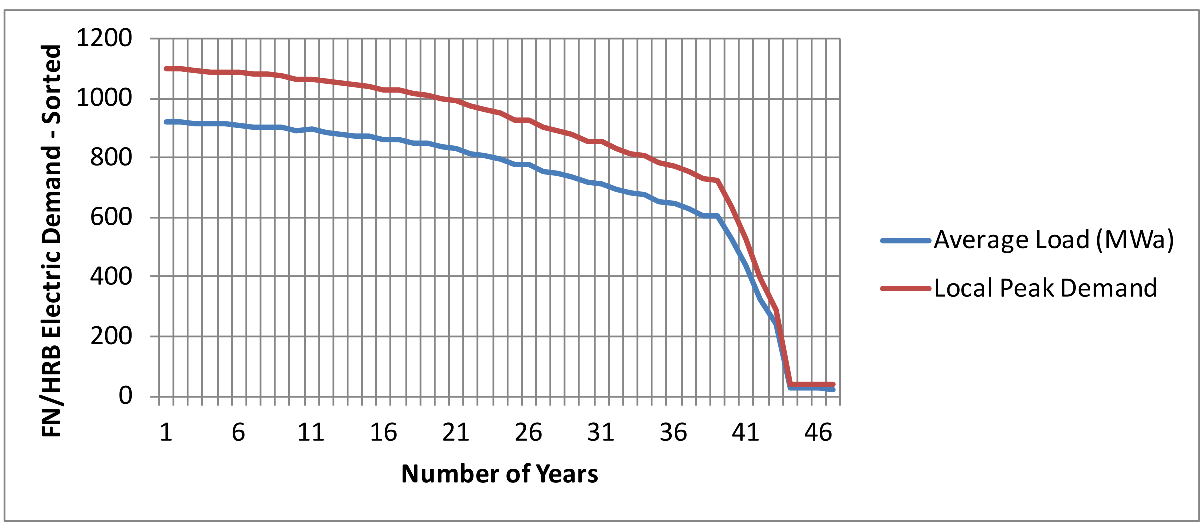
The economic life of any facilities acquired or constructed by BC Hydro would depend, at least in part, on the resulting loading. In Figure 13, a duration curve of the above load level provides an indication of the electricity service requirements. For example, in this mid HRB natural gas production level and mid electrification scenario, there would be 38 years with a local coincident peak load over 400 MW, and 21 years over 600 MW.

Figure 13 Duration of Customer Demand in Mid/Mid Scenario



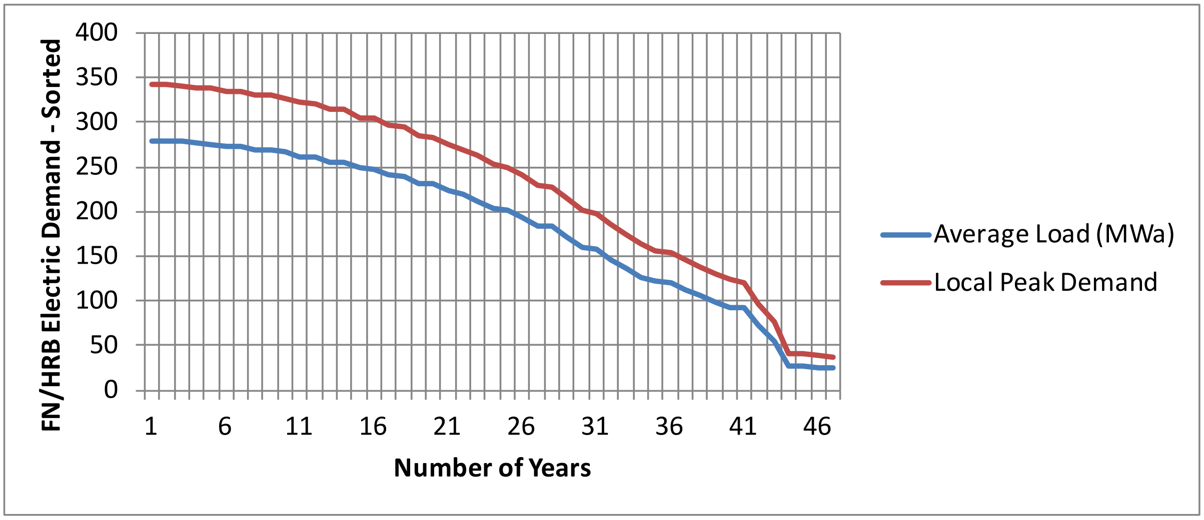
In the high production and high electrification scenario, the sorted electrical demand is as shown in Figure 14. In this case, there would be 37 years over 750 MW, and 19 years over 1,000 MW.

Figure 14 Duration of Customer Demand in High/High Scenario



In the low production and low electrification scenario, the duration curve would be as shown in Figure 15. In this scenario, there are 36 years over 150 MW and 24 years over 250 MW.

Figure 15 Duration of Customer Demand in Low/Low Scenario



The above three load duration graphs provide an indication of the volume risk that exists when deciding whether capital-intensive resources such as transmission and generation should be committed to meet the potential load in the Fort Nelson/HRB.

Further, all three of the above scenarios assume that carbon sequestration of formation CO_2 occurs, and that the compressors to provide that work are electrified. If this is not the case, the expected electrical load would be proportionately lower.

6.2 Economic Analysis for Fort Nelson/HRB

In this subsection, the BC Hydro costs that would be incurred for the three production/electrification scenarios (high/high, mid/mid, low/low), across three market price scenarios (Market Scenario 1, 2 and 3), are presented for each of the strategies analyzed. The costs are PV costs in $2013 for the period 2014-2060.

This cost comparison cannot be used in isolation of the overall context, and other analyses. There is a significant difference in loads served across some of the strategies, and such differences must be considered when making any conclusions based in whole or in part on these costs.

The base metric for much of this analysis is the PV of load served by BC Hydro. This metric is the Present Value (**PV**) of GWh served, as shown in Table 4. In this series of strategies, the lowest load served represents the load that BC Hydro would serve if BC Hydro was only responsible for meeting the current Fort Nelson load. The highest load served is in the gas-fired generation cases where the generation is all located at FNG. The load is somewhat higher than the other full Fort Nelson/HRB service strategies simply as a result of system transmission losses.

Table 4 PV of Load Served under Various Strategies

	1	2	3	4	5	6	7	8
2014-2060: PV at 5.0% discount rate.	Alternative 1	Alternative 2					Alternative 3	
	System	Fort Nelson/HRB Network				HRB Alone	Fort Nelson Alone	
	1	2A3	2A1(1)	2A1(2)	2A2	2B(1)	3(1)	3(1)
	BC Hydro Clean	Wind & LMS100	1 Cogen Plant	2 Cogen Plants	CCGT LM6000	1 Cogen	New Fort Nelson Reserve (LMS100)	
	With Sequestration							No Sequest.
	BC Hydro-Supplied Electricity (PV of GWh)							
High Production/ Electricity Scenario	83,522	88,096	91,477	91,355	91,477	85,874	4,759	4,759
Mid Production/ Electricity Scenario	49,554	52,267	54,273	54,214	54,273	48,975	4,759	4,759
Low Production/ Electricity Scenario	23,567	24,858	25,812	25,336	25,812	21,633	4,759	4,759

6.2.1 BC Hydro's Total Costs

Total costs for the above combination of scenarios and strategies are presented in Table 5, with the following observations:

- Where BC Hydro is serving the full Fort Nelson/HRB load, (Columns [1] – [5]):
  - A local clean or renewable strategy of wind, backed by SCGTs (Alternative 2A3, Column [2]) is never the low-cost strategy
  - A supply strategy based on clean or renewable energy from the BC Hydro integrated system (Alternative 1, Column [1]) is relatively more expensive

    - than other strategies under Market Scenarios 1 and 2, while the difference in cost is significantly reduced or eliminated under Market Scenario 3
    - Strategies relying on gas-fired generation are clearly the lowest cost under Market Scenarios 1 and 2; while the difference in cost to the BC Hydro system clean or renewable energy strategy (Column [1]) is significantly reduced or eliminated under Market Scenario 3
    - Within the gas-fired generation strategies, the CCGT strategy (Column [5]) is in the middle of the cost range. This is because it does not rely on heat sales, as co-generation facilities do. Co-generation strategies with the highest heat sales load (in this set of analysis represented by Alternative 2A1(2), Column [4]), show up as having the best cost characteristics
- Where BC Hydro is serving Fort Nelson and the HRB separately with different regional networks (the HRB strategy Alternative 2B1), (Column [6])
    - Analytical trends for co-generation are similar to the full Fort Nelson/HRB network, but the costs are allocated across a smaller load

Table 5 BC Hydro's Total PV of Costs ($ million)

		1	**2**	**3**	**4**	**5**	**6**	**7**	**8**
2014-2060: PV in $2013 at 5.0% discount rate.		Alt. 1	Alternative 2					Alternative 3	
		System	Fort Nelson/HRB Network				HRB Alone	Fort Nelson Alone	
		1	2A3	2A1(1)	2A1(2)	2A2	2B(1)	3(1)	3(1)
		BC Hydro Clean	Wind & LMS100	1 Cogen Plant	2 Cogen Plants	CCGT LM6000	1 Cogen	New Fort Nelson Reserve (LMS100)	
		With Sequestration							No Sequest.
		BC Hydro Total Cost to Serve Fort Nelson/HRB (as required for Scenario) (PV $million)							
High Production/ Electricity Scenario	Market Scenario 1	12,197	11,154	9,560	8,322	9,847	8,543	392	392
	Market Scenario 2	12,075	9,966	7,341	6,518	8,051	6,675	312	312
	Market Scenario 3	12,360	12,440	11,960	10,272	11,789	10,562	480	480
Mid Production/ Electricity Scenario	Market Scenario 1	6,821	6,765	5,574	5,109	5,792	4,852	392	392
	Market Scenario 2	6,698	6,049	4,328	4,004	4,710	3,854	312	312
	Market Scenario 3	6,983	7,540	6,921	6,303	6,961	5,930	480	480
Low Production/ Electricity Scenario	Market Scenario 1	3,085	3,480	2,737	2,374	2,737	2,377	392	392
	Market Scenario 2	2,963	3,150	2,171	2,042	2,171	1,947	312	312
	Market Scenario 3	3,246	3,837	3,349	2,734	3,349	2,844	480	480

6.2.2 BC Hydro's Average Cost

The results of BC Hydro's average cost per MWh of electricity served presents a similar metric to total cost, but combines the load differential between the scenarios, and makes the results more comparable to other costs in the broader IRP.

Table 6 presents the results of the same set of scenarios and strategies. With respect to the Columns [1] to [6] that include service to the combined Fort Nelson/HRB and the strategy to serve HRB alone, the additional observations to those above include:

- The costs per MWh of the system clean or renewable strategy (Column [1]) are relatively stable in the $130/MWh to $150/MWh range, and are relatively insensitive to market prices, which would indicate that infrastructure costs (primarily transmission) are reasonably well absorbed
- The cost per MWh of strategies that rely on natural gas generation (Columns [3] to [6]) are relatively low compared to almost any expected cost of new supply, with the strategy involving two co-generation plants (Column [4]) being the lowest
- Directionally, there is little difference between the Fort Nelson/HRB network results (Columns [3] to [5]) and the HRB-alone network results (Column [6]) for the gas-fired strategies

Table 6 BC Hydro's Incremental Cost of Supply to Fort Nelson/HRB (PV in $/MWh)

		1	2	3	4	5	6	7	8
2014-2060: PV in $2013 at 5.0% discount rate.		Alt. 1	Alternative 2					Alternative 3	
		System	Fort Nelson/HRB Network				HRB Alone	Fort Nelson Alone	
		1	2A3	2A1(1)	2A1(2)	2A2	2B(1)	3(1)	3(1)
		BC Hydro Clean	Wind & LMS100	1 Cogen Plant	2 Cogen Plants	CCGT LM6000	1 Cogen	New Fort Nelson Reserve (LMS100)	
		With Sequestration							No Sequest.
		BC Hydro's Cost to Serve Fort Nelson/HRB (as required for Scenario) (PV in $/MWh)							
High Production /Electricity Scenario	Market Scenario 1	146	127	105	91	108	99	82	82
	Market Scenario 2	145	113	80	71	88	78	66	66
	Market Scenario 3	148	141	131	112	129	123	101	101
Mid Production/ Electricity Scenario	Market Scenario 1	138	129	103	94	107	99	82	82
	Market Scenario 2	135	116	80	74	87	79	66	66
	Market Scenario 3	141	144	128	116	128	121	101	101
Low Production/ Electricity Scenario	Market Scenario 1	131	140	106	94	106	110	82	82
	Market Scenario 2	126	127	84	81	84	90	66	66
	Market Scenario 3	138	154	130	108	130	131	101	101

6.3 GHG Production Analysis

In this section, the results of the amount of vented CO_2 are analyzed. In the case of the overall Fort Nelson/HRB, the results include vented CO_2 from both formation and combustion processes. In the case of BC Hydro's share, the results are only for combustion CO_2.

The modelled results for GHG production, as measured by volumes in mega tonnes (**MT**)/year of vented CO_2, are insensitive to Market Price scenarios, because the resources and dispatch are the same for each strategy analyzed.

6.3.1 Overall Fort Nelson/HRB

GHG emission production is highest with a strategy where the HRB development proceeds assuming producers self-supply their electricity and heat requirements, and there is no CO_2 sequestration (Column [8]). In this strategy, the PV of MT of GHGs is 273 MT, 195 MT and 98 MT for the high, mid and low production scenarios respectively (refer to Table 7).

If carbon capture and sequestration of formation CO_2 could be successfully implemented, those amounts can be reduced to 121 MT, 86 MT and 44 MT for the three scenarios respectively (Column [7]). This indicates that approximately 55 per cent of the overall GHG vented can be eliminated without BC Hydro's involvement, again assuming that sequestration can be successfully implemented.

With BC Hydro supplying the region clean energy strategy from the integrated system, the overall vented GHGs can be further reduced to 73 MT, 59 MT and 31 MT for the same respective scenarios (Column [1]). This represents a cumulative reduction of approximately 70 per cent (middle of Table 7), or an incremental improvement after sequestration of 30 to 40 per cent (bottom of Table 7).

The BC Hydro strategies based on gas-fired generation have less of an incremental impact. For example, the CCGT strategy (Column [5]) provides an incremental improvement over the producers self-supply sequestration strategy of four to seven per cent, whereas a successfully implemented co-generation strategy (Column [4]) is somewhat higher. A BC Hydro local area isolated network clean strategy (Alternative 2A3, Column [2]) falls in between the system clean (Column [1]) and the gas-fired strategies (Columns [3] to [6]), providing an incremental improvement over producer self-supply sequestration strategy of approximately 15 per cent.

Table 7 Overall Fort Nelson/HRB GHG Production

	1	2	3	4	5	6	7	8
2014-2060: PV at 5.0% discount rate.	Alternative 1	Alternative 2					Alternative 3	
	System	Fort Nelson/HRB Network				HRB Alone	Fort Nelson Alone	
	1	2A3	2A1(1)	2A1(2)	2A2	2B(1)	3(1)	3(1)
	BC Hydro Clean	Wind & LMS100	1 Cogen Plant	2 Cogen Plants	CCGT LM6000	1 Cogen	New Fort Nelson Reserve (LMS100)	
	With Sequestration							No Sequest.
	CO2 Vented – Formation and Combustion (PV of Megatonnes)							
High Production/ Electricity Scenario	73.3	99.4	120.7	110.0	112.8	115.1	121.2	273.4
Mid Production/ Electricity Scenario	58.7	74.1	84.2	80.2	82.0	81.3	86.2	195.0
Low Production/ Electricity Scenario	30.5	37.7	42.1	36.8	42.1	41.4	44.3	97.8
	GHG per cent Reduction from No Sequestration (% of PVs of Megatonnes)							
High Production/ Electricity Scenario (%)	73.2	63.7	55.8	59.8	58.8	57.9	55.7	
Mid Production/ Electricity Scenario (%)	69.9	62.0	56.8	58.9	58.0	58.3	55.8	
Low Production/ Electricity Scenario (%)	68.8	61.4	56.9	62.4	56.9	57.6	54.7	
	GHG per cent Reduction from With Sequestration (% of PVs of Megatonnes)							
High Production/ Electricity Scenario (%)	39.5	18.0	0.4	9.3	6.9	5.0		
Mid Production/ Electricity Scenario (%)	31.9	14.1	2.3	7.0	4.9	5.7		
Low Production/ Electricity Scenario (%)	31.0	14.7	4.8	16.8	4.8	6.3		

6.3.2 BC Hydro's Share of GHG Production

The CO_2 produced and vented from resources owned or acquired by BC Hydro is presented in Table 8. With these strategies, a supply strategy based on clean energy from the BC Hydro integrated system results in the lowest GHG emissions, even when considering the producer self-supply strategy.

Table 8 CO2 Produced by BC Hydro Facilities in Fort Nelson/HRB

	1	2	3	4	5	6	7	8
2014-2060: PV at 5.0% discount rate.	Alternative 1	Alternative 2					Alternative 3	
	System	Fort Nelson/HRB Network				HRB Alone	Fort Nelson Alone	
	1	2A3	2A1(1)	2A1(2)	2A2	2B(1)	3(1)	3(1)
	BC Hydro Clean	Wind & LMS100	1 Cogen Plant	2 Cogen Plants	CCGT LM6000	1 Cogen	New Fort Nelson Reserve (LMS100)	
	With Sequestration							No Sequest.
	BC Hydro CO2 Production (PV of Megatonnes)							
High Production/ Electricity Scenario	0.3	26.4	54.4	54.3	39.7	50.4	2.1	2.1
Mid Production/ Electricity Scenario	0.3	15.7	32.2	35.7	23.6	28.4	2.1	2.1
Low Production/ Electricity Scenario	0.3	7.5	16.9	13.4	16.9	13.2	2.1	2.1

Co-generation strategies (Columns [3], [4] and [6]) generally show higher CO_2 for BC Hydro than the CCGT strategy (Column [5]). One observation that needs mentioning is that BC Hydro's share of GHG production is not necessarily aligned with GHG emissions from the overall FN/HRB region. While co-generation strategies show higher CO_2 than the CCGT strategy, much of the increase is because of a transfer of GHG liability from the host processing plant to BC Hydro's co-generation plant. The co-generation plants are less efficient for electricity production (thus higher CO_2 venting) than CCGTs, and make up the efficiency gain by heat sales, which reduce the GHG produced at the host processing plant.

For example, the mid production scenario for Column [4] co-generation strategy shows 35.7 MT of CO_2 production, which is higher than the 23.6 MT in the CCGT strategy (Column [5]). For the overall CO_2 production in the mid production scenario, Table 8 shows the same co-generation strategy at 80.2 MT (Column [4]), with the CCGT strategy showing 82.0 MT. Thus, on an overall basis, Alternative 2A1(2) (Column [4]) shows a relatively low GHG production, while BC Hydro's total amount of GHG increases.

6.3.3 BC Hydro's Cost per Tonne of GHG reduction

A BC Hydro clean or renewable electricity strategy as compared to any of the alternative gas-fired strategies can be considered as an incremental cost towards an incremental reduction in Provincial GHG emissions production. Table 9 provides the cost per tonne to take the total BC Hydro cost for each strategy and scenario that includes gas-fired generation, to the equivalent scenario's system clean strategy (notionally a cost to upgrade each BC Hydro gas generation strategy to a clean electricity strategy).

For example, on the first row (High Production/High Electricity and Scenario 1), starting from Alternative 2A1(1) (the one co-gen plant, Column [3]), the incremental GHG cost to take that strategy and convert it to a system clean strategy would be $79/tonne. The cells shaded green indicate strategies and scenarios that would benefit by being converted to system clean or renewable strategies, relative to the assumed incremental GHG offset costs for each Market Scenario, as reflected in the analysis by the BC Carbon Tax of $30/Tonne.

The results show:

- The additional cost for upgrading to a system clean strategy from any of the gas fired generation strategies is generally higher than the expected GHG costs being offset
- The strategy of local clean energy with back-up gas-fired resources is economic compared to the system clean strategy in the Low Load Scenario based on the expected GHG costs being offset.

Table 9 Incremental Cost to Upgrade from Gas-Fired Strategy to System Clean Electricity Strategy

		1	2	3	4	5	6	7	8
2014-2060: PV in $2013 at 5.0% discount rate.		Alt. 1	Alternative 2					Alternative 3	
		System	Fort Nelson/HRB Network				HRB Alone	Fort Nelson Alone	
		1	2A3	2A1(1)	2A1(2)	2A2	2B(1)	3(1)	3(1)
		BC Hydro Clean	Wind & LMS100	1 Cogen Plant	2 Cogen Plants	CCGT LM6000	1 Cogen	New Fort Nelson Reserve (LMS100)	
		With Sequestration							
		Effective Cost/Tonne GHG Reduction to Upgrade to System Clean (PV)							**Market Scenario CO_2 $/T**
High Production /Electricity Scenario	Market Scenario 1		70	79	102	90	103		30
	Market Scenario 2		111	118	133	132	138		30
	Market Scenario 3		27	37	69	44	66		30
Mid Production/ Electricity Scenario	Market Scenario 1		34	69	78	74	100		30
	Market Scenario 2		72	104	106	115	131		30
	Market Scenario 3		(6)	32	49	31	67		30
Low Production/ Electricity Scenario	Market Scenario 1		(25)	51	84	51	85		30
	Market Scenario 2		4	78	100	78	109		30
	Market Scenario 3		(52)	24	69	24	61		30

7 Government Policy Measures

7.1 93 per cent Clean or Renewable Energy Objective

Table 10 presents the effect that each of the alternative supply strategies would have on BC Hydro's ability to meet the 93 per cent clean or renewable energy objective. The BC Hydro load for the integrated system, without Fort Nelson/HRB, is the mid load forecast; while the thermal generation is the Island Generation, McMahon and Prince Rupert facilities.

The analysis results are as follows:

- For the supply strategy based on BC Hydro supplying the region with clean or renewable energy from the integrated system (Column [1]), BC Hydro is above the 93 per cent clean or renewable energy objective
- For the supply strategy for Fort Nelson alone (Columns [7] and [8]), BC Hydro is above the 93 per cent clean or renewable energy objective
- For the gas-fired generation strategies (Columns [3] to [6]), BC Hydro is below the 93 per cent clean or renewable energy objective in the mid and high load scenarios, but above the 93 per cent clean or renewable energy objective in the low load scenario
- For Alternative 2A3 (Column [2]), regional clean or renewable energy supply with back-up gas-fired resources, BC Hydro is below the 93 per cent clean or renewable energy objective only in the high load scenarios; the other two scenarios are above 93 per cent

Given the PV costs of serving a Fort Nelson/HRB low load scenario (approximately 350 MW) based on a gas-fired generation strategy are lower relative to a system-based clean energy strategy, BC Hydro may wish to preserve some of its 7 per cent non-clean headroom as an option to support supplying the Fort Nelson load growth and electrification of the HRB.

Table 10 Comparison of Alternatives to 93 per cent Clean Energy Objective

	1	2	3	4	5	6	7	8
	Alternative 1	Alternative 2					Alternative 3	
	System	Fort Nelson/HRB Network				HRB Alone	Fort Nelson Alone	
	1	2A3	2A1(1)	2A1(2)	2A2	2B(1)	3(1)	3(1)
	BC Hydro Clean	Wind & LMS100	1 Cogen Plant	2 Cogen Plants	CCGT LM6000	1 Cogen	New Fort Nelson Reserve (LMS100)	
	With Sequestration							No Seequest.
	BC Hydro Total System per cent B.C. Clean Electricity (Average 2020 – 2030)							
High Production/ Electricity Scenario (%)	95.8	91.4	87.9	87.9	87.9	88.4	95.1	95.1
Mid Production/ Electricity Scenario (%)	95.7	93.1	91.0	91.0	91.0	91.5	95.1	95.1
Low Production/ Electricity Scenario (%)	95.6	94.2	93.1	93.1	93.1	93.5	95.1	95.1

8 Risk Analysis

8.1 Stranded Investment Risk

The economic and GHG analysis presented in section 6 provide a range of results for differing uncertainties relating to BC Hydro's load (natural gas production and electrification intensity) and market prices.

This section looks at some of the residual risk elements that cannot easily be quantified in that type of analysis. The analysis looks at some of the uncertainties from a perspective of what is at risk if the conditions unfold differently than planned.

A key risk from a long-term planning perspective is the risk of stranded assets. For example, for the supply strategy based on clean or renewable energy from the BC Hydro integrated system, if the Fort Nelson/HRB load that is planned for does not materialize (the risk possibility), then the risk consequence would be:

- Low for the clean or renewable resources that may have been acquired, as these resources could be redeployed for meeting general integrated system load growth or supply retirements
- High for the Northeast Transmission Line as there would be no alternative use for most of the NETL (the segment between Peace Region and North Peace Region may provide access to cost-effective clean energy resources to serve system requirements)

Similarly, in the case of supply strategies based on co-generation plants, the risk probability lies in the possibility that either the electrical load or the heat load does not materialize or continue at the level expected, in which case the risk consequences would be:

- Very high for the co-generation plant, which could lose one or both markets
- Zero for the NETL from Peace Region to FNG, because that transmission segment is not required

A comparison of stranded asset risk across the alternatives is summarized in Table 11.

Table 11 BC Hydro Stranded Asset Risk Matrix

Supply Strategies/Drivers for Stranded Asset Risk	**System Clean**	**Local Clean / SCGT**	**CCGT at Fort Nelson (self-own/ tolling)**	**Co-gen at Fort Nelson (take or pay)**	**Co-gen in HRB (take or pay)**
Stranding Drivers					
Horn River Basin Production/Electrification	Yes	Yes	Yes	Yes	Yes
Host Co-generation Competitiveness	No	No	No	Yes	Yes
Supply Components					
Electricity Supply – Capacity	Low (redeploy)	High	High	High	Very high
Electricity Supply – Energy	Low (redeploy)	High	Low	High	Very high
GMS to NPR Transmission	Low (redeploy)	Zero (N/A)	Zero (N/A)	Zero (N/A)	Zero (N/A)
NPR to Fort Nelson Transmission	High	High	Zero (N/A)	Zero (N/A)	Zero (N/A)
Fort Nelson to HRB Transmission	High (equal)	High (equal)	High (equal)	High (equal)	Zero (N/A)
Sub-transmission	High (equal)	High (equal)	High (equal)	High (equal)	High (equal)

9 BC Hydro Only Supplying Fort Nelson

Based on the mid load forecast and high load scenario for Fort Nelson, BC Hydro will need to add new capacity resources in order to maintain N-1 level of reliability as shown in Figure 2. Until new supply solution is implemented, some Fort Nelson load may be subject to curtailable service. Accordingly, BC Hydro is working with the AESO to develop a Fort Nelson area load control process and remedial action schemes for events of supply shortfall.

For meeting load up to 73 MW on a firm basis, BC Hydro could construct new gas-fired peaking generation in Fort Nelson (i.e., SCGT) in Fort Nelson, or contract additional FTS service from Alberta via the AESO. The AESO has indicated that it will not offer transmission service beyond 75 MW.

Analysis of the Alternative 3 (Fort Nelson alone) strategies provides a comparison between a local SCGT and increased FTS service from the AESO. Table 12 and Table 13 present results that focus only on the Fort Nelson alone (Alternative 3) strategies, and present the differences between relying on a new peaking SCGT as compared to increasing reliance on Alberta. For this analysis, only the Fort Nelson mid-load forecast was considered.

Table 12 BC Hydro's Total Costs (PV in $million)

Supply Alternatives		Alternative 3(1): New Fort Nelson LMS100 SCGT	Alternative 3(2) AESO
Mid Production/ Electricity Scenario	Market Scenario 1	392	468
	Market Scenario 2	312	388
	Market Scenario 3	480	556

Table 13 BC Hydro Incremental Cost of Supply to Fort Nelson/HRB ($/MWh)

Supply Alternatives		Alternative 3(1): New Fort Nelson LMS100 SCGT	Alternative 3(2) AESO
Mid Production/ Electricity Scenario	Market Scenario 1	82	98
	Market Scenario 2	66	82
	Market Scenario 3	101	117

The above results show that selecting a SCGT is always lower cost than increased FTS reliance on Alberta. In both cases, the incremental energy served would be thermal-based, so there is no material difference for clean or renewable electricity targets.

If: (a) BC Hydro does not undertake a strategy that involves electrifying the Fort Nelson/HRB region; and (b) it determines new supply is required, then: adding peaking capacity or emergency capacity to FNG to meet Fort Nelson load on a firm basis appears to be the lowest cost and preferable alternative.

In such an event, further studies would be required to select the most appropriate peaking capacity, given the expected loads. The IRP analysis was based on the LMS100 SCGT. Because of its size relative to the supply requirements (as presented in Section 2.3), it is likely the largest unit that would be required. Smaller sized additions or alternative supply configurations will need to be analyzed at part of future studies.

In this strategy of BC Hydro continuing to supply only Fort Nelson (and not electrifying the HRB region), the stranded asset risk is related to adding local generating capacity to serve future load that does not materialize when expected. As noted in Section 2.3 there are significant uncertainties to the Fort Nelson area mid load forecast due to potential impacts from Horn River Basin development and/or other load developments such as a restart of currently shut-down forestry mills. These uncertainties could defer the expected capacity shortfall to beyond F2018, or cause the shortfall to occur earlier than F2018. As such, any decision to add local generating capacity will be contingent on the load forecast becoming more certain.

10 Conclusions

BC Hydro studied alternatives for supplying the combined Fort Nelson/HRB loads under mid, high and low electrification load scenarios and under Market Scenarios 1, 2 and 3.

BC Hydro believes a definitive decision on whether or not to electrify the HRB is not required at this time; and that it should continue to work with government, industry and private sector generation proponents in assessing the merits of electrifying the HRB.

Specific findings supporting the summary conclusion are as follows:

- A system clean or renewable resource strategy is relatively more expensive than other strategies under Market Scenarios 1 and 2; while the difference in cost is significantly reduced or eliminated relative to gas-fired strategies under Market Scenario 3
- A system clean strategy can reduce GHG emissions by 30 to 40 per cent relative to producer self-supply
- This option allows for lower cost integration of clean/renewables resources in the North Peace region and loads that would otherwise not be electrified; however the integration benefit does not offset total costs relative to the gas fired generation alternative
- Within the gas fired generation strategies:
  - CCGT strategies are less volatile since they do not rely on heat sales. CCGTs have less market risk than co generation (more flexible commercial mechanisms, no heat host risk), but miss some of the potential thermal efficiency that might exist from well-balanced cogeneration
  - Cogeneration appears to be the lowest cost option, but requires a good long term balance and consistency of heat load and electric load; and require that commercial risks can be adequately addressed; BC Hydro acquired cogeneration shifts more (most) GHG emissions to BC Hydro
  - Gas fired generation strategies can reduce GHG emissions by 0 to 16 per cent relative to producer self-supply its energy and electricity requirements, but do not meet the 93 per cent clean energy objective other than in a low load scenario
- A local clean or renewable (wind) backed by SCGTs strategy is never the low cost strategy

Under the scenario where HRB gas producers self-supply their energy requirements, BC Hydro must continue to supply existing and future Fort Nelson load. The two options for serving Fort Nelson load are continued/increased firm service from Alberta and new gas fired generation at Fort Nelson. The key findings of the analysis are:

- Gas fired generation operating as reserve and/or peaking capacity is the most cost effective new supply option for serving Fort Nelson load
- The alternative of increasing transmission service from Alberta will require significant upgrades in Alberta, the costs to increase to 75 MW (approximately $300 million) would largely be allocated to BC Hydro
- BC Hydro's existing transmission service contract of 38.5 MW is based on embedded cost of service rates and not likely to face significant rate increases
- This Fort Nelson only supply option is not needed if BC Hydro provides electricity service to the HRB via transmission connection to Fort Nelson or transmission connection to the integrated system
- Until Fort Nelson only or Fort Nelson/HRB supply is developed and if load in the Fort Nelson region exceeds 38.5 MW, a portion of Fort Nelson industrial customers will not have N-1 service and may be subject to curtailable service until additional generation can be built
- BC Hydro has identified and assessed a number of risks and uncertainties associated with providing electricity supply to Fort Nelson/HRB
- First and foremost, the HRB has significant, but uncertain electrification potential. Absent load certainty, all supply alternatives expose BC Hydro to different types and levels of stranded investment risk
- While some proponents in industry continue to express interest in both electrification and CCS as a means of reducing GHG emissions in the HRB, there remains significant uncertainty with respect to industry's commitment to take electricity service. Clarity on industry's view may only come through better

identification of the opportunities, costs and risks of electrification, and allocation of the costs and risks between the entities.

- Current lower natural gas market prices and production forecasts suggests the expected ramp up of HRB development has slipped somewhat. This may provide some additional time to identify a workable solution; but must recognize the speed that industry can mobilize, once decisions are made.
- In addition, liability of vented formation CO2 needs to be addressed; its inclusion and ownership will heavily influence both the scale of HRB development, and the type of work supply alternative that would be most economic

With 70 per cent of total GHG emissions consisting of formation CO2, meaningful emissions reductions will require carbon capture and sequestration.

Conclusions in this Fort Nelson section support Recommended Actions No. 13 and 17 as described in Chapter 8.