Additional Industrial Electricity Load Growth in B.C. to 2025

Prepared for the

Canadian Wind Energy Association

By

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Executive Summary

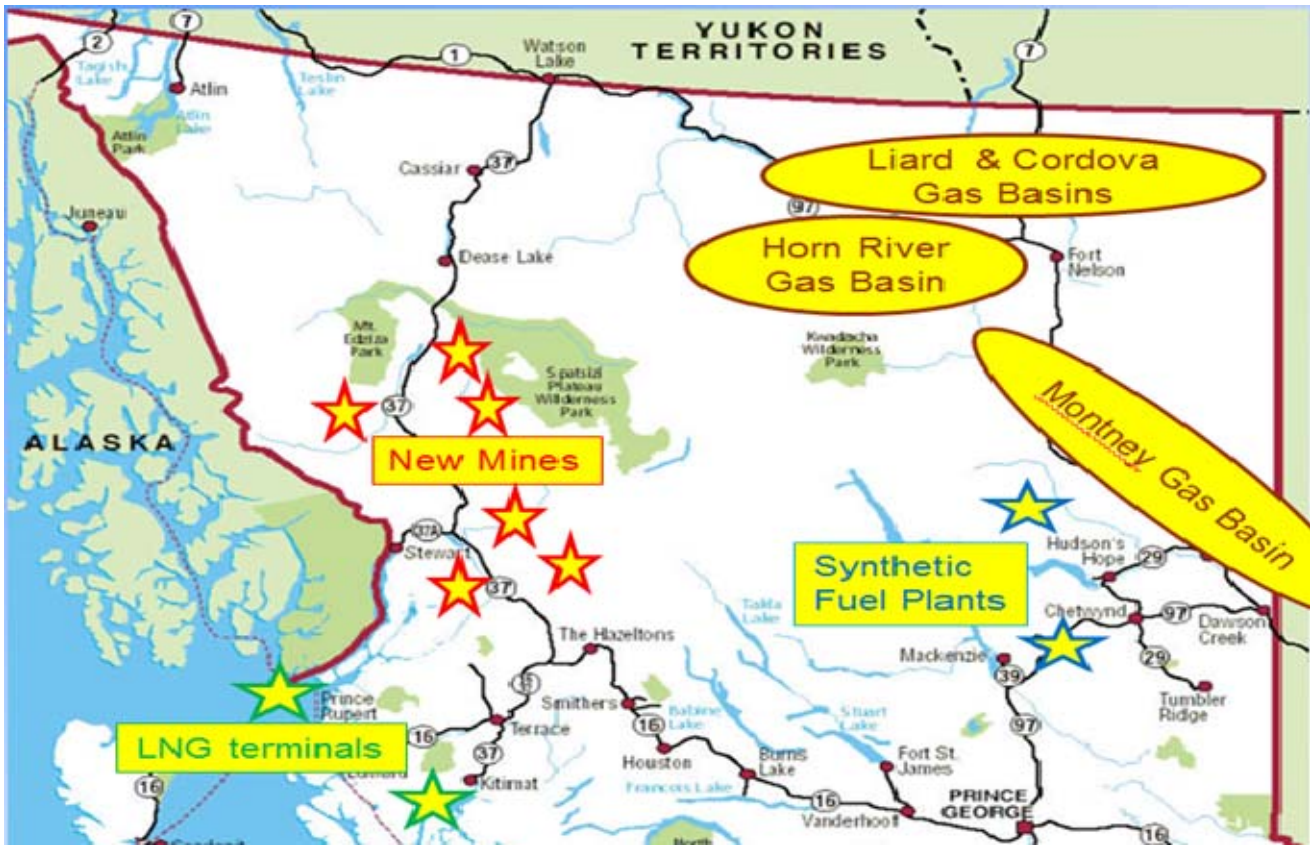
CanWEA commissioned this report to inform its BC WindVision 2025 analysis with a forecast of the market for wind energy in BC in both 2017 and 2025.

BC Hydro included an estimate of industrial electricity load for 2017 and 2025 within its latest load forecast, dated December 2010. Since that time, however, there have been announcements of dozens of new mines, several LNG terminals and significant investments in northeast shale gas exploration and production activities. If even a modest proportion of these proposals come to fruition they will consume a substantial amount of energy. Additionally, CanWEA wanted to see the impact on electricity load growth in those sectors if the fuel switching and transmission expansion policy priorities in BC's new Clean Energy Act and the province's GHG Reduction Target Act were fully and promptly implemented.

This report identifies and quantifies the six industrial sectors with the most potential to require substantial amounts of new electricity. These sectors are:

1. Montney Basin natural gas activities,
2. Horn River Basin natural gas activities,
3. Liard/Cordova Embayment Basin natural gas activities,
4. New Liquefied Natural Gas terminals and pipelines,
5. New mines, and
6. New plants to produce alternative transportation fuels.

Figure ES – 1: Map of locations of six sector loads



The potential new electricity load for each sector was calculated by means of the following steps;

I. **Reviewing** the BC Hydro December 2010 Load Forecast for that sector, for both electricity load quantities and the assumptions on which work functions would be electrified, and chosen levels of electrification intensity and service percentage.

II. **Totaling** the new Potential Work Energy requirements that could result from the many new projects or higher production forecasts that have been announced for each sector since BC Hydro's December 2010 Load Forecast.

III. **Discounting** this Potential Work Energy to account for reasonable levels of project attrition, so that the number of newly announced plants that actually get built, or recently announced production levels that are actually delivered, adequately reflects the challenges of developing new industrial plants in BC and the volatility of mineral and gas commodity prices.

IV. **Further Discounting** this Potential Work Energy to account for real-world limitations on the maximum amount of electrification that could be reasonably expected to occur. This calculation includes assumptions on the number of electrifiable work functions, levels of electrification intensity, and service percentages.

This report relies on public information including BC Hydro publications, BCUC and NEB filings and recent news articles and releases and various organizations websites. The report authors are not privy to other information that BC Hydro may have on additional physical or economic constraints that may temper the higher levels of electrification intensity and service percentages, as well as the timing of transmission extensions, that have been assumed in the report.

This study assumes that a larger number of electrifiable work functions, higher levels of electrification intensity and service percentages, and faster transmission extensions can be achieved if the government and BC Hydro fully and promptly implement the relevant aspects of the Clean Energy Act and GHG Reduction Target Act.

Where a work function can be electrified or the construction of a transmission line can be accelerated then, within reason, this report assumes that will be done. As such, this report assumes that grid-based electricity service can be made available to new plants and activities at a faster pace than has occurred in recent years.

In short, this report suggests that the available load should determine what transmission and generation will be required, rather than constraining the degree of electrification to fit within the current limitations on transmission capacity or the availability of generation to serve that load.

BC Hydro, on the other hand, as the implementer of electricity policies, has the responsibility for rules and rates, and as the builder of transmission lines, has the more challenging task of evaluating the cost and the economic justification for these lines. Additionally, it must co-ordinate those actions with the highly detailed B.C-wide utility work schedules that are already in motion.

The information and analysis presented in this report indicates that a larger number of new mines, LNG terminals, and alternative transportation fuel plants will get built than appear in BC Hydro's 2010 Load Forecast. The divergence in the result of these two studies appears to be produced by two factors.

- First, a considerable amount of new information has become available since the 2010 Load Forecast was created.
- Second, this report assumes the maximum practical amount of this new demand is electrified and supplied with clean or renewable electricity as a means of achieving cost stability, lower costs over the long term, and large reductions in greenhouse gas emissions relative to providing this energy demand by means of natural gas or diesel-fuelled sources.

In the eight months since December 2010, not only have many more new projects been announced, but many proposed projects have also passed important development milestones. As they pass milestones, like securing permits or financing or agreements with local First Nations, the likelihood they will actually get built significantly increases.

This report also assumes a higher level of natural gas exploration, extraction and processing in the northeast shale basins than appears in BC Hydro's 2010 Load Forecast. Again, this is based on new information that has become available in the last eight to ten months. Higher gas production forecasts and reserve potential estimates have recently been published by the Ministry of Energy, the Canadian Association of Petroleum Producers (CAPP), large gas companies, and BC Hydro itself.

In addition to increasing the Potential Work Energy requirements for the northeast gas sector, this increases both the pace and the scale at which electrification of the industry's activities and work functions could be implemented.

The most important example of the impact of new information is the increased production forecasts for Horn River and the surge in land acquisition and exploration investment in the Liard Basin, which improve the business case for extending the Northeast Transmission Line (NETL). The sooner BC Hydro decides to build the NETL, the sooner grid electricity will be available to those customers. This means more work functions will be electrified and the level of electrification intensity and the service percentage will increase. These effects all combine to result in higher and faster electricity load growth for the three sectors in the northeast gas region.

There is no doubt the potential new work activities identified in all six sectors will consume some form of energy. Not all will be electrified. However, if these energy needs are not served by clean renewable electricity supplied by the main BC Hydro grid, then it is highly probable they will be served by fossil fuel energy, with all of its associated greenhouse gas (GHG) implications.

Drill rigs, pipeline compressors and processing plants in the Horn River area, for example, do not currently have access to BC Hydro's grid-based electricity service. They use fossil-fuelled generators and compressors to produce their energy, which create significant GHG emissions. These emissions could be substantially reduced if grid-based electricity, more than 90% of which is generated from clean and renewable energy sources, was readily available. If it is not available, the drilling, compressing and processing won't stop. It will simply be driven by more and more fossil-fuelled generators and compressors.

The BC *Clean Energy Act* (2010) includes the following objectives to:

> *reduce BC greenhouse gas emissions … by 2020 and for each subsequent calendar year to at least 33% less than the level of those emissions in 2007… and by such other amounts as determined under the Greenhouse Gas Reduction Targets Act;*

and to:

> *encourage the switching from one kind of energy source or use to another that decreases greenhouse gas emissions in British Columbia.*

As noted above, this report assumes and recommends that government and BC Hydro implement GHG reduction measures, including fuel switching (i.e. from diesel or gas generation to grid-based clean renewable electricity), and accelerate transmission extensions (i.e. NETL) and interconnections (to new mines) as fully and promptly as is reasonably possible.

More specifically, this study assumes that a higher level of electrification is achieved than shown in recent BC Hydro studies; that more mines and LNG terminals are electrified, that there is a higher level of gas production (and thus, more electric load) from shale gas resource areas, and that within all of these sectors, more functions are electrified and higher levels of electrification intensity and service percentages are achieved.

Discounting for project attrition

The Mid Case forecast presented in this report assumes that most of the many announced new projects will not actually be built and that shale gas production will fall short of many industry projections in order to account for the significant challenges of developing industrial projects in BC and the high volatility of mineral and gas prices.

For Montney Basin, the report uses CAPP's gas production forecast, which is 19% lower than BC Hydro's 2025 High Forecast and 43% below the customer requests they have already received. For Horn River, the report's gas production forecast is an average of two gas industry forecasts. The result is 46% lower than BC Hydro's 2025 High Forecast. For Liard/Cordova, even though these basins have a larger area than Horn River, this report assumes a gas production forecast that is only 50% of the Horn River levels, and defers production by eight years, even though the current pace of land rights acquisition indicates that the Liard and Cordova regions are only about three to four years behind Horn River.

For LNG, the report assumes that only one of the four large LNG terminals that have been announced will be built by 2017. One of these proposed projects expects to receive its National Energy Board permit within a month and aims to start construction around the end of this year. A much smaller LNG terminal, co-led by a local First Nation, has also applied for its LNG permit and is also forecast to be built by 2017. By 2025, the report assumes only one of the other three announced LNG projects will be built.

For new mines, the report assumes that, of the 206 projects that are at various stages of development, only four will be built by 2017 and only two more built by 2025. This is fewer than half of the most advanced 14 new mines that are already at the final stages of permitting or environmental assessment, each representing a substantial financial commitment by the proponent towards development.

Two companies have announced plans to build multi-billion dollar plants that would produce transportation fuels using alternatives to petroleum oil. Despite the strong business case of record spreads between oil and natural gas prices, the projected increase in the cost of carbon emissions, and governmental desire to reduce dependence on oil imports, this report assumes only one of these two plants will be built and allows 14 years, until 2025, for it to be operational.

The resulting projection of potential new work energy from these six sectors is shown below:

Table ES-1: Mid Case forecast of potential electrifiable work energy (GWh)

Sector:	***2017***	***2025***
Montney Basin natural gas activities	4,083	4,742
Horn River Basin natural gas activities;	3,812	5,771
Liard/Cordova Embayment Basin natural gas activities;	0	1,906
New Liquefied Natural Gas terminals and pipelines;	4,736	9,054
New mines; and	3,330	4,486
New plants to produce alternative transportation fuels	0	4,200
Total	**15,961**	**30,159**

A High Case forecast was also prepared for this study. This forecast assumed that a higher proportion of announced mines and terminals get built and higher - but not the highest available - gas production projections occur. Under the High Case forecast, total potential new work energy reaches approximately 28,000 GWh in 2017, and approximately 48,000 GWh in 2025. This High Case forecast is described in Chapter 5.

Discounting for potential electrification

The report's Mid Case forecast of 30,000 GWh of potential new work energy in 2025 and 16,000 GWh in 2017 includes potentially electrifiable energy required by these activities. However, not all of this demand for energy will be met using electricity. For instance, some may be too far from the grid, or some may be too spread out to justify extending wires everywhere. In addition, projects that also require heat may find co-generation cheaper if gas or diesel prices are low.

To adjust for the degree of electrification, each sector's load is discounted for a reasonable degree of electrification, as follows:

Table ES-2: Forecast Degrees of Electrification by sector (%)

Sector:	***2017***	***2025***
Montney Basin natural gas activities	73%	74%
Horn River Basin natural gas activities;	70%	70%
Liard/Cordova Embayment Basin natural gas activities;	n/a	70%
New Liquefied Natural Gas terminals and pipelines;	83%	83%
New mines; and	70%	70%
New plants to produce alternative transportation fuels	100%	100%
Average:	**75%**	**79%**

Multiplying the potential work energy in each sector by its projected Degree of Electrification results in the Potential Load for each sector, which breaks down as follows:

Table ES-3: Potential Load by sector – after allowance for electrification of work energy (GWh)

Sector	Major Potential Work Energy Identified		Degree of Project Electrification		Major Potential Load After Allowance for Electrification	
	2017	2025	2017	2025	2017	2025
Montney Basin O&G	4,083	4,742	*73%*	*73%*	2,997	3,483
Horn River Basin O&G	3,812	5,771	*70%*	*70%*	2,659	4,027
Cordova/Liard O&G	-	1,906	-	*70%*	-	1,334
LNG Pipelines+Terminals	4,736	9,054	*84%*	*83%*	3,956	7,559
New Mines	3,330	4,486	*70%*	*70%*	2,331	3,140
Alternative Fuel Plants	-	4,200	*100%*	*100%*	-	4,200
TOTAL	15,961	30,158	*75%*	*79%*	11,943	23,743

The table shows that after allowance for electrification the Mid Case forecast of total potential load is almost 12,000 GWh for 2017 and almost 24,000 GWh for 2025.

Comparison to BC Hydro 2010 Load Forecast:

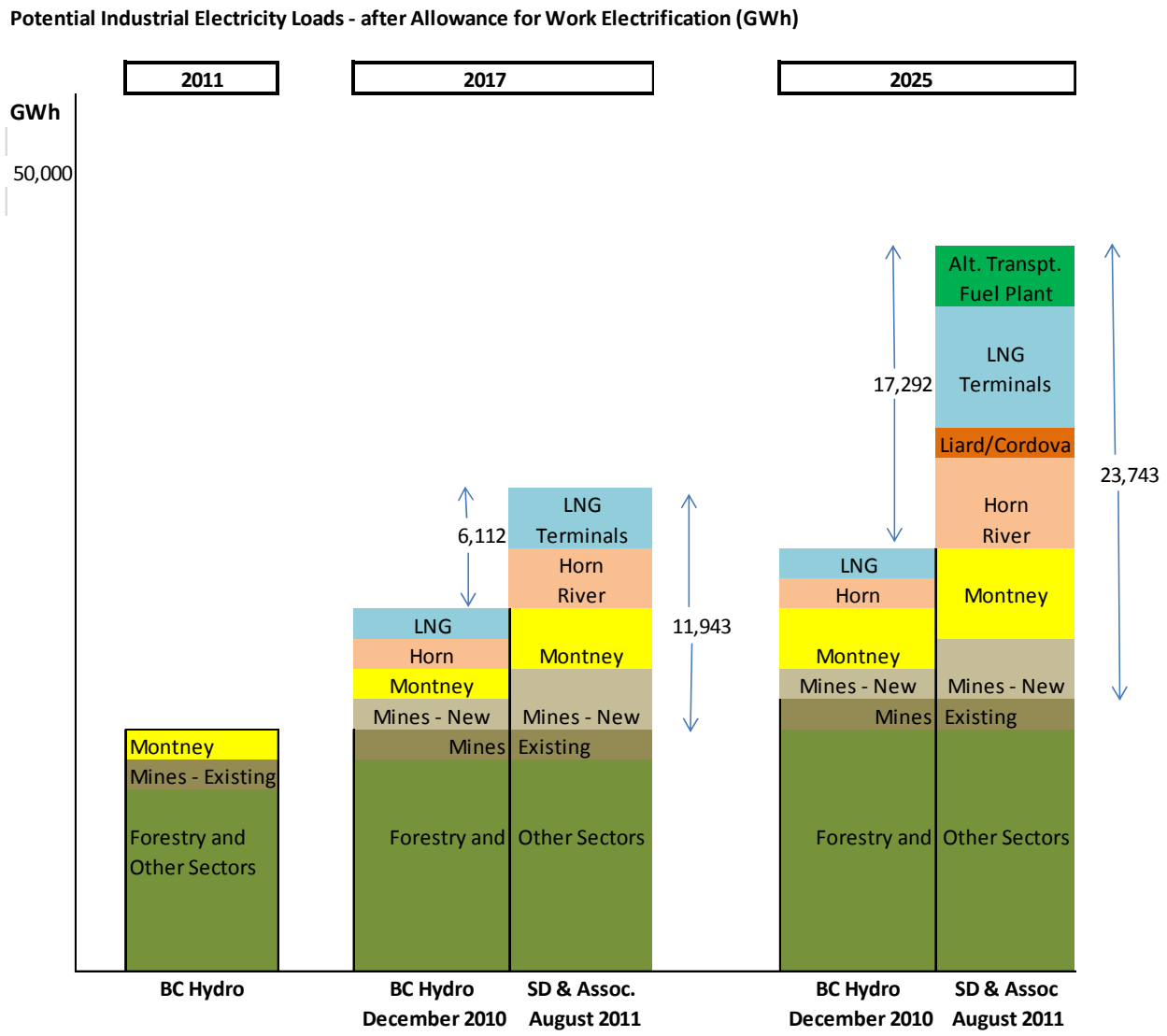
The potential loads from these six sectors in 2017 and 2025 shown in Table 1-3 above can be compared with the Mid Case scenario in BC Hydro's 2010 Load Forecast. The resulting net increase in projected electricity load over and above that shown in the BC Hydro 2010 load forecast is referred to as the "Supplemental Load" in Table ES-4 below:

Table ES-4: Comparing Forecast Electrified Load with BC Hydro 2010 Load Forecast (GWh)

Sector	Major Potential Load After Allowance for Electrification		Amount included in Dec. 2010 Load Forecast		Supplemental Electric Load Potential Identified	
	2017	2025	2017	2025	2017	2025
Montney Basin O&G	2,997	3,483	1,939	2,359	1,058	1,124
Horn River Basin O&G	2,659	4,027	892	1,092	1,767	2,935
Cordova/Liard O&G	-	1,334	-	-	-	1,334
LNG Pipelines+Terminals	3,956	7,559	1,100	1,100	2,856	6,459
New Mines	2,331	3,140	1,900	1,900	431	1,240
Alternative Fuel Plants	-	4,200	-	-	-	4,200
TOTAL	11,943	23,743	5,831	6,451	6,112	17,292

These results are also shown in the following graph, which layers them on top of the load growth forecast for BC Hydro's other industrial loads, which includes forestry, existing mines and other industrial sectors (shown in green and brown at the bottom of each load stack). This report made no attempt to review load growth projections for these other sectors.

Figure ES-2: Forecast Industrial Electricity Load (Mid Case) (not to scale)



As shown in the figure above, the results of this report provide a Mid Case forecast of additional electrical load for six industrial sectors in BC that indicates a supplemental load of 6100 GWh in 2017, effectively doubling BC Hydro's own load forecast of new industrial load to this date.

By 2025, this study indicates a net additional load of 17,300 GWh, increasing total industrial load by 50% relative to BC Hydro's 2010 Load Forecast. If this load is added to the rest of the industrial loads in BC Hydro's 2010 Load Forecast, the total industrial load in BC will be increased from around 18,000 GWh today, to almost 45,000 GWh by 2025.

As noted above, this significant difference in forecasts appears to largely be the result of two factors.

- First, important new information has become available in the last eight to 10 months that supports projections of higher levels of electrification and faster transmission extensions, which would make clean, renewable grid-based electricity readily available to these fast-growing sectors and reduce their GHG emissions.
- Second, this analysis assumes that as a consequence of the province's energy and climate change policies as well as BC's legislated greenhouse gas reduction targets, the government and BC Hydro encourage maximum feasible electrification of potential new loads, and accelerate the extension of the transmission system to deliver required energy to these industrial customers.

Another fundamental difference between this report's forecast and BC Hydro's 2010 Load Forecast comes from the fact that this report does not constrain the potential load to fit the available transmission or generation capacities. Instead, this report assumes that realistic projections of potential load should determine what transmission and generation will be required, rather than constraining the degree of electrification to fit within the current limitations on transmission capacity or the availability of generation to serve new load.

This approach is consistent with recommendations in CanWEA's "WindVision for BC" document that BC Hydro and government should do all that is reasonably possible to encourage the maximum degree of feasible electrification of these six fast growing sectors' loads, and to accelerate the extension of the transmission system to deliver the required electricity to these industrial customers.

Chapter 1: Scope and Methodology

1.1 Scope

This report is not intended to be an electricity load forecast for British Columbia as a whole, or even the province's industrial sector. Rather, this report attempts to set out an updated Mid Case forecast of additional electricity demand from a small number of specific industrial sectors. More specifically, this report focuses on those sectors thought to have the greatest potential for increased energy demand relative to that indicated in BC Hydro's most recent projection of domestic electricity load, where this additional demand for energy can substantially be met using electricity. This report is not intended to be an electricity load forecast for British Columbia as a whole, or even the province's industrial sector.

The study team decided to focus the report on the following six areas (referred to in the report as "sectors") with significant potential load growth:

1. Montney Basin natural gas activities,
2. Horn River Basin natural gas activities,
3. Liard/Cordova Embayment Basin natural gas activities,
4. New Liquefied Natural Gas terminals and pipelines,
5. New mines, and
6. New plants to produce alternative transportation fuels.

This report focuses on the industrial sectors of natural gas production, LNG export terminals, new mines, and alternative transportation fuel plants because the large number of major recent announcements in these areas has given them a significantly increased likelihood of requiring large amounts of new work energy within the next ten to fifteen years.

The study team assumed the BC Hydro load forecast of 2010 to be accurate. However, new information has become available since the completion of this load forecast. In addition, this study assumes that the electrification of new energy demand will be pursued aggressively by the government and BC Hydro.

1.2 Methodology

In order to derive a Mid Case forecast of electricity demand, the study team first identified all of the potential development in each of the six identified sectors.

Working from announcements for proposed projects and industry projections, the study team then identified a Mid Case estimate of the new industrial work energy requirements for each sector in the years 2017 and 2025, assuming a high level of project attrition. The information reviewed and the resulting determination of total work energy requirements for each examined sector is set out in Chapter 2. The Mid Case forecast represents a reasonably probable total of "potentially electrifiable" work energy for each sector based on information available as of August 2011. The study team assumed that where it was possible, transmission would be extended to new loads.[1]

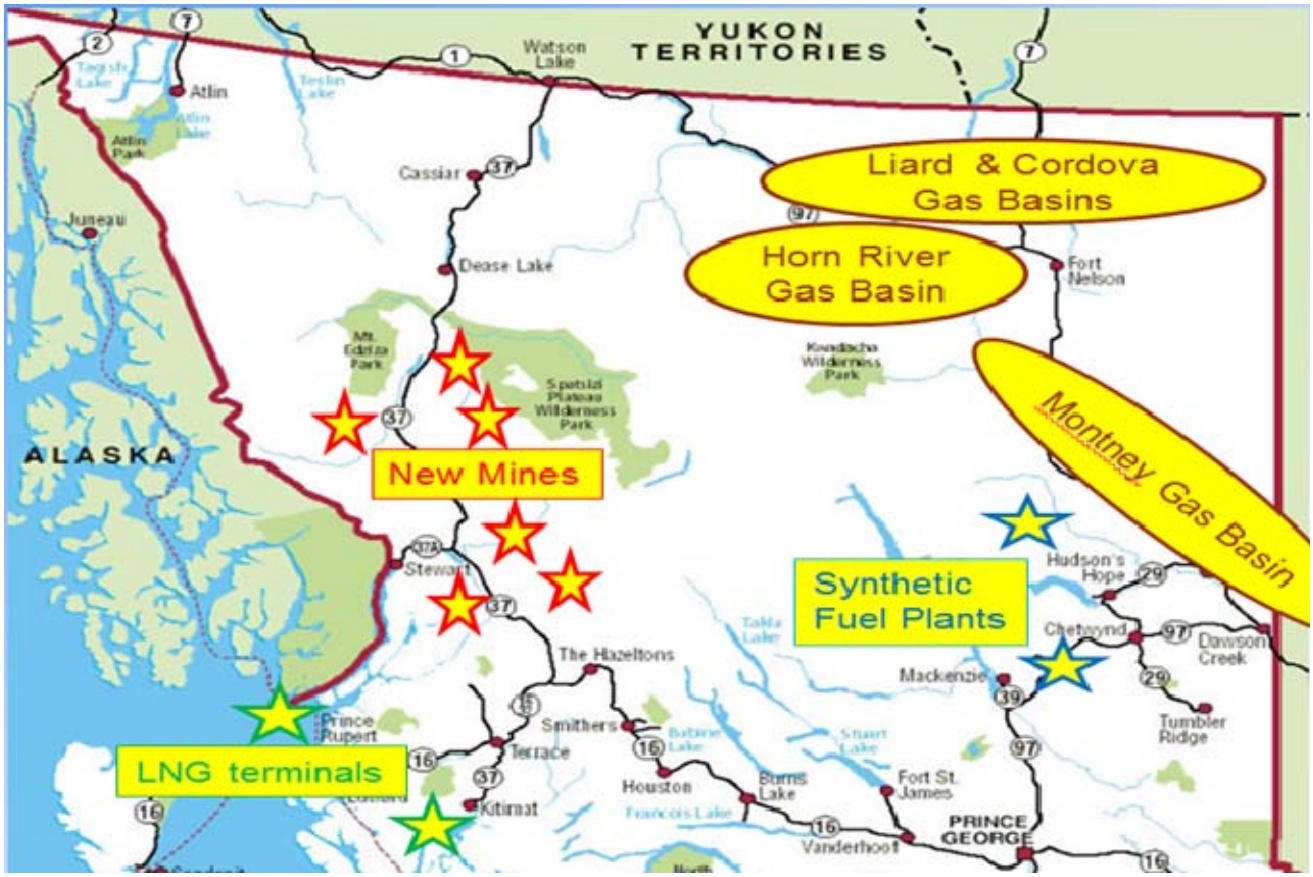
Chapter 3 reviews the BC Hydro load forecast of December 2010 in order to determine as accurately as possible what amount of load growth the utility has already included in its forecast for these six project areas.

Chapter 4 specifies the degree of electrification that could be achieved within each of the six industrial sectors, assuming the full and prompt implementation of the *Clean Energy Act* and the *GHG Reduction Targets Act*, and that where a work function can be electrified or a transmission line can be accelerated, this is done and done promptly. These electrification factors are then used to derive the gross supplemental electricity load for each of the six sectors. This chapter also compares the Mid Case forecast developed for the six sectors above with the BC Hydro forecast (issued in December 2010). Load growth for each sector already captured within the BC Hydro load forecast is factored out to produce a net additional electricity load total for each of the six sectors, for both the mid-range and high-end forecasts of load growth.

Chapter 5 presents a High Case Forecast. Compared to the Mid Case Forecast, the High Case assumes a more modest level of project attrition and a higher degree of electrification.

The report concludes with high level recommendations and a summary.

Figure 1 -1: Map of locations of six sector loads



[1] For example, the study team considers the construction of the Northeast Transmission Line (NETL) to the Horn River Basin by 2017 to be practical, whereas extending the NETL to the Liard region by 2017 is not. Similarly, the study team did not consider extension of the Northwest Transmission Line to mines up near the Yukon border by 2017 to be practical.

Chapter 2: Mid Case Analysis and Forecast

2.1 Sector # 1: Montney Basin Shale Gas Activity

This section describes the Mid Case forecast of potential new electricity load required by natural gas activities in the Montney Basin. It includes a background introduction, gas production forecasts from BC Hydro and CAPP, the conversion of those gas production forecasts to electricity load requirements, the identification and quantification of elements that affect the breadth and depth of electrification, and the impact of GHG emissions and policies on electrification.

Background

The Montney Basin is a region of shale gas development near Dawson Creek, BC. It is already connected to the main electricity grid (referred to as the Integrated Area).

As of March 31, 2011 there were approximately 665 producing wells in the Montney trend. The BC Oil and Gas Commission (OGC) in its late-2010 report, estimates Initial Recoverable Raw Gas Reserves for the Montney at 7.94 trillion cubic feet (Tcf), up 58% from the previous year due to performance revision and drilling additions. Only a small portion of the Montney play is currently developed. This is an immense energy resource, with an estimated cost of production that is expected to make it competitive with other shale gas basins in North America.

Electricity is potentially usable for processing plants and pipeline compression. The annual load growth in the Montney area is approximately 10 times the average annual rate of load growth in BC.

This is mostly due to an unprecedented increase in planned natural gas extraction in the area. The use of electric compression by producers for operational flexibility, fuel and operating cost reductions, and GHG abatement has the potential to result in significant electrical load growth.

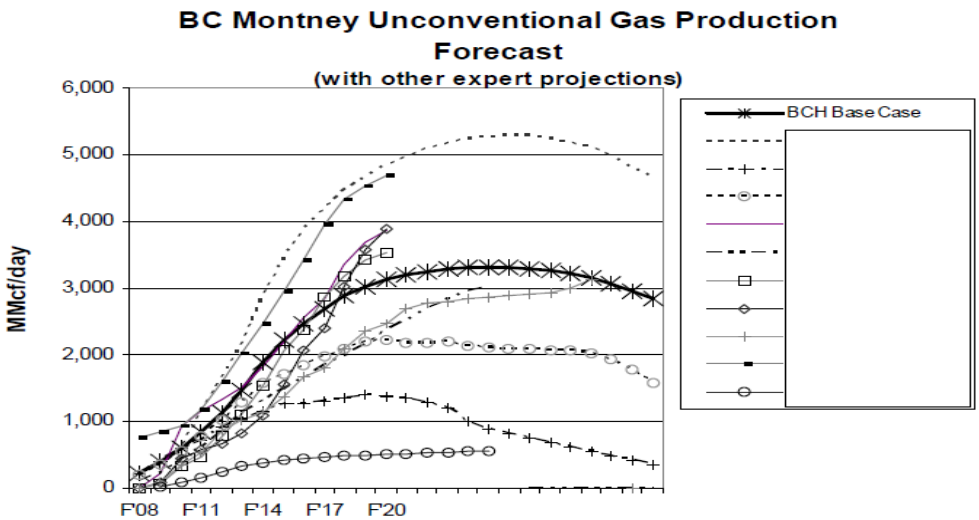
Electricity loads for Montney Basin gas activities have the potential to increase through:

- Increased gas production forecasts (as indicated by increased customer requests for service);
- Broadening the range of functions to be electrified; and
- Increasing the penetration of electrical service within those functions that can be electrified.

BC Hydro Gas Production Forecasts:

There are a wide variety of gas production forecasts, as reflected in the following graph from BC Hydro's December 2010 Load Forecast.

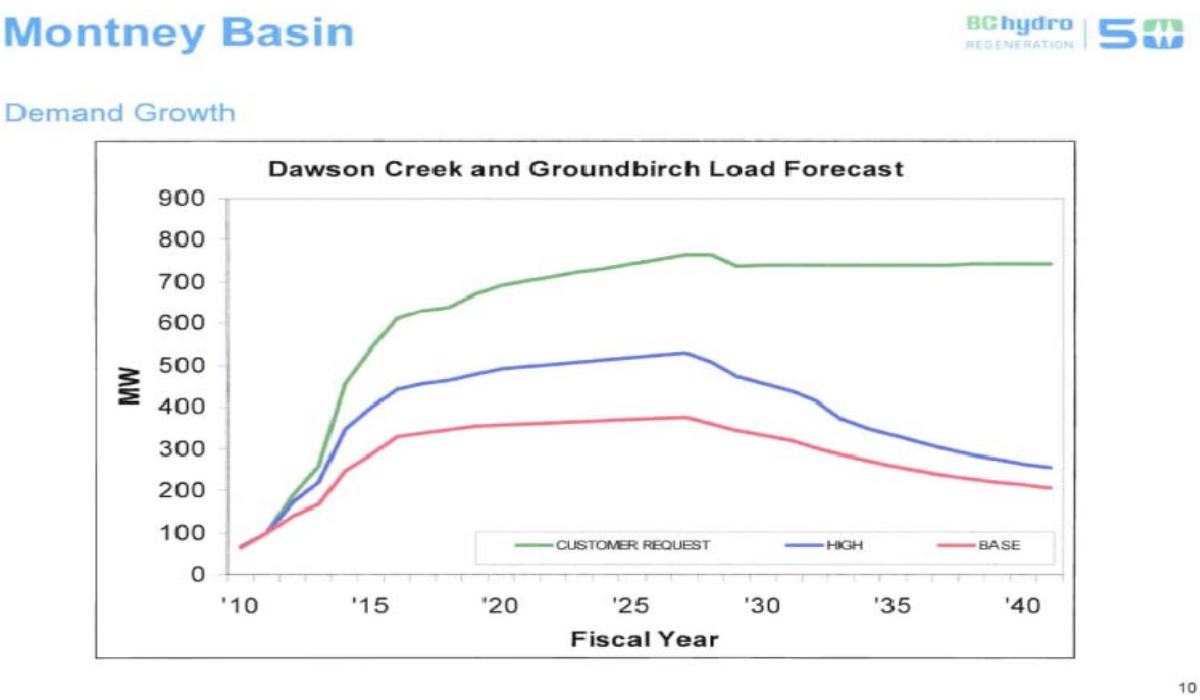
Figure 2.1 - 1 – BC Hydro Gas Production Forecast for Montney[1]



BC Hydro's "BASE" load forecast was based on the darkest curve in the middle of the other expert projections.

BC Hydro also estimated a "HIGH" load forecast for the Montney Basin area, shown as the middle line in Figure 2.1-2 below (taken from a BC Hydro presentation from June 2011).

Figure 2.1-2 – BC Hydro Base and High Forecasts, and BC Hydro Customer Requests for electrical service[2]



Since the 2010 Load Forecast was developed in the fall of 2010, there has been a tremendous increase in customer requests for new electrical service, and these requests are reflected in the highest line of the chart.

These June figures, and particularly the topmost line labeled "Customer Request" indicate a significant upward trend in the projected electricity demand for the Montney Basin since the 2010 Load Forecast was developed in the fall of 2010.

The BC Hydro representative confirmed that "Dawson Creek and Groundbirch Load" is approximately 85% of the total expected gas producer load for the entire Montney basin. Assuming an 80% load factor to convert from MW of capacity to GWh of energy consumption, the following table sets out the projected gas production forecasts and electrical energy requirements of these three BC Hydro forecasts:

Table 2.1-1 –BC Hydro Forecasts for Montney: BASE, HIGH, and Customer Requests

Major Load Potential #1 - Montney Basin Oil & Gas

Montney Basin O&G			Forecast 1 BCH BASE Forecast 2010 Load Forecast		Forecast 2 BCH HIGH Forecast 2010 Load Forecast		Forecast 3 BCH Customer Requests June, 2011	
	Notes	Units	2017	2025	2017	2025	2017	2025
Gas Production Forecast	(1)	MMcf/d	2,698	3,312	4,706	5,320	6,445	7,570
Electric Intensity of Included Work	(2)	MW/MMcf/d	0.115	0.115	0.115	0.115	0.115	0.115
MW of Power for Included Work	(3)	MW	310	381	541	612	741	871
Load Factor	(4)	%	80.4%	80.4%	80.4%	80.4%	80.4%	80.4%
Annual Included Work Energy Required	(5)	GWh/yr	2,185	2,683	3,812	4,309	5,220	6,132
Energy Proposed for BCH Service	(6)	GWh/yr	1,939	2,359	1,939	2,359	1,939	2,359
Implied Service/Electrification %	(7)	%	88.7%	87.9%	50.9%	54.7%	37.1%	38.5%
Net Un-Electrified Included Work Energy	(8)	GWh/yr	246	324	1,873	1,950	3,281	3,773

Notes

(1) For Forecast 1, Gas Production is input from 2010 Load Forecast, Appendix 3.2, Table A3.1 Integrated Area (Peace Region)
For Forecasts 2 and 3, Gas Production is back-calculated from line 3 / line 2

(2) Intensity of 0.115 is assumed for all forecasts, based on BC Hydro's calculations in the 2010 Load Forecast, Appendix 3.2, page 98
Electric Intensity is the power in MW required to drive the included work processes, needed to achieve a gas production rate in millions of cubic feet per day
Included Work processes are those viewed as most readily electrifiable, such as moving the gas from the RGTs to the processing plant but not the drilling, fracturing or new pipeline loads

(3) For Forecast 1, Power Required = line 1 x line 2
For Forecasts 2 and 3, Power is estimated from BC Hydro's chart "Dawson Creek and Groundbirch Load Forecast" / 0.85
Dawson Creek and Groundbirch is assumed to comprise 85% of the total Montney production potential (per D. Little of BCH, June 2010 presentation)

(4) A Load Factor of 80.4% is used for all forecasts, based on the value used in BCH's DCAT Application, Appendix B, page 82 of 100, to convert 275 MW to 1,938 GWh in F2025

(5) Annual Included Work Energy Required (in GWh) is calculated from Power (in MW) x Load Factor x 8,760 hr / 1,000

(6) Energy Proposed for BC Hydro Service is the amount shown in the 2010 Load Forecast, Appendix 3.2, page 94, Table A3.1

(7) The Implied Service/Electrification % is the proportion of the Annual Included Work Energy that BCH is forecasting to service in its 2010 Load Forecast

(8) The Net Un-Electrified Work Energy is the balance of the Included Work Energy that must be obtained from other sources, most likely fossil fuels

(Note that these numbers reflect the 2010 Load Forecast for the total Montney region, adjusted from the "Dawson Creek and Groundbirch" numbers as depicted in the previous chart).

Relatively speaking, the BC Hydro "High" gas forecast represents an increase of about 60% over the "Base" forecast that was used in the 2010 Load Forecast, while the "Customer request" level is about 128% higher than the Base level in 2025. BC Hydro staff advised the study team that:

> *"The Base (reference forecast) is used in the December 2010 load forecast and represented BC Hydro's expected gas production and associated degree of electrification at the time the 2010 Load Forecast was prepared. The High [forecast] represents what the electric load would result if a higher-than-expected gas production scenario unfolded. The Customer Requests includes the aggregate total of all entities that have formally requested electric service or have made enquiries of BC Hydro for providing electricity services, as of May 2011. These requests may include potential projects not directly related to natural gas production and projects which are considered to be speculative at this point."* [3]

In its July 2011 Application for its Dawson Creek/Chetwynd Area Transmission Project, BC Hydro states:

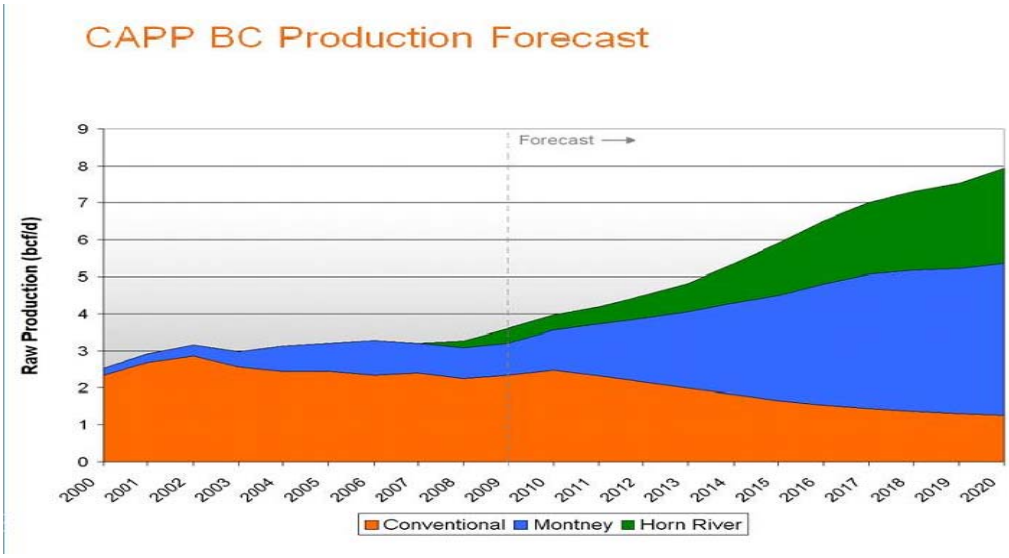
> *"… there have been recent receipt of inquiries for new load, requests for interconnection studies, public announcements on proposed gas developments, and collaborative government-gas industry efforts aimed at helping the province meet its GHG emission targets. Therefore, BC Hydro believes that there is an increasing probability that future gas production and associated electrical load will be higher than the current forecast than lower."*[4]

This report agrees with BC Hydro that the current updated projection of electrical loads in the Montney region is likely to be higher than reflected in the 2010 Load Forecast. For comparison purposes, we show the following forecast from the Canadian Association of Petroleum Producers.

CAPP Production Forecast for Montney Basin

In late 2010, the Canadian Association of Petroleum Producers (CAPP) published the following forecast, which includes Montney and the Horn River Basin:

Figure 2.1 -3 – CAPP Forecast for Montney and Horn River Basin[5]



Adding this forecast into the previous table of BC Hydro forecasts provides the following comparisons:

Table 2.1-2 – Three BC Hydro Forecasts plus CAPP Forecast

Major Load Potential #1 - Montney Basin Oil & Gas

Montney Basin O&G	Forecast 1 BCH BASE Forecast 2010 Load Forecast		Forecast 2 BCH HIGH Forecast 2010 Load Forecast		Forecast 3 BCH Customer Requests June, 2011		Forecast 4 CAPP Forecast Producers Forecast 2010	
	2017	2025	2017	2025	2017	2025	2017	2025
Gas Production Forecast	2,698	3,312	4,706	5,320	6,445	7,570	3,700	4,300
Electric Intensity of Included Work	0.115	0.115	0.115	0.115	0.115	0.115	0.115	0.115
MW of Power for Included Work	310	381	541	612	741	871	426	495
Load Factor	80.4%	80.4%	80.4%	80.4%	80.4%	80.4%	80.4%	80.4%
Annual Included Work Energy Required	2,185	2,683	3,812	4,309	5,220	6,132	2,997	3,483
Energy Proposed for BCH Service	1,939	2,359	1,939	2,359	1,939	2,359	1,939	2,359
Implied Service/Electrification %	88.7%	87.9%	50.9%	54.7%	37.1%	38.5%	64.7%	67.7%
Net Un-Electrified Included Work Energy	246	324	1,873	1,950	3,281	3,773	1,058	1,124

For Forecast 4, the Gas Production Forecast has been estimated from the CAPP Forecast chart above, and the other lines are calculated using the same assumptions as the BC Hydro forecasts.

The CAPP production forecast is intermediate between BC Hydro's "Base" and "High" forecasts (about 30% above the "Base" forecast by 2025). In view of BC Hydro's statement that future load is likely to be higher than the 2010 Load Forecast, rather than lower, **this report suggests the CAPP forecast as a plausible, but still conservative, updated estimate of the future gas production activity in the Montney Basin area.**

However, gas production activity is only one factor in determining the amount of potential electrical energy load. Other factors which can have a significant effect on the electrical load include:

a) The amount of 'Included' Work - the functions considered eligible to be electrified:

BC Hydro bases its electrical load forecast on the assumption that only certain functions will be electrified and only at a certain fraction of the sites. – i.e. not all the work activities and not all the sites. For instance, BC Hydro's 2010 Load Forecast states that the drilling and *"hydraulic fracturing operations would not be serviced by BC Hydro… water recycling loads would not be material…"* and *"new pipeline loads would not be serviced."*[6]

The electricity for these activities is currently being provided by diesel generators. If government policy required companies to switch to using clean electricity from the grid, and if the transmission grid was extended to these facilities, these could become additional new loads.

b) The intensity of the use of electricity to perform the 'Included' Work:

The term 'intensity' is used to describe the amount of electricity required for each unit of gas produced. This is largely a function of which work activities are 'included' as potentially electrifiable, but it does not include all of the work activities.

BC Hydro's 2010 Load Forecast forecasts an intensity of 0.115 MW/MMcfd.[7] It also mentions that some industry surveys show higher intensities of 0.13 MW/MMcfd. If the intensity was increased to that level, it would increase loads by 13%.

Increasing the CAPP Forecast amounts by 13% would add another 390 GWh of 'Included' Work Energy required in 2017 and 450 GWh in 2025.

BC Hydro staff advised the study team that:

> *"BC Hydro's load forecast reflects a degree of electrification within the gas sector – i.e. the percentage of gas production that will be supplied by BC Hydro to meet its work energy requirements versus gas production whose work energy requirements will be self-supplied. For the Dawson Creek and Groundbirch areas, BC Hydro expects a high percentage (95%) of utility-supplied service."*[8]

c) Service Percentage:

Once the potentially electrifiable activities are estimated, then that energy is multiplied by factor referred to as the 'service percentage.' The service percentage is the proportion of potentially electrifiable energy to be provided electricity service by BC Hydro. Essentially, these are the sites and functions for which BC Hydro plans to provide electricity service.

BC Hydro's 2010 Load Forecast forecasts a weighted average service percentage of 90% across five areas in the Montney basin (assuming Dawson Creek and Groundbirch are 85% of all Montney).[9] If the service percentage was increased to 95% (the level targeted for Dawson Creek) in all five areas, the electrical loads would increase 5%.

Increasing the CAPP Forecast amounts by 5% would add another 150 GWh in 2017 and 175 GWh in 2025.

GHG Emissions:

Increased gas production at Montney results not only in increased electricity demand, but also increased GHG emissions. Increased emissions run counter to the provincial government's *Greenhouse Gas Reduction Targets Act* and international agreements, and could trigger significant future carbon-related costs or liabilities to the province and/or to the emitters.

Maximizing the amount of Montney activities driven by clean electricity from BC Hydro's grid will reduce emissions compared to the use of diesel or gas-fuelled generators. In addition to the obvious environmental benefits, reducing GHG emissions also promises to deliver significant financial savings as costs on carbon increase over time, and are applied to a broader range of emission sources. These emission reductions and carbon cost savings can be realized in several ways:

- expanding the extent of areas serviced by the grid (i.e. the Service Percentage),
- increasing the number of work activities that are electrified (i.e. the Work Included) and
- increasing the degree of electrification of those activities (i.e. the Intensity).

Accordingly, GHG emissions impact both the amount and the economics of electricity load growth.

The amount of electrification forecast specified in the 2010 Load Forecast will reduce the GHG emissions from the Montney shale gas activities by less than 33% and leave untouched almost three megatonnes (Mt) of new GHG emissions by 2025, as shown in the lower half of the following table:

Table 2.1-3 – Forecasts 1, 2, and 4, showing Greenhouse Gas (GHG) Consequences

Major Load Potential #1 - Montney Basin Oil & Gas

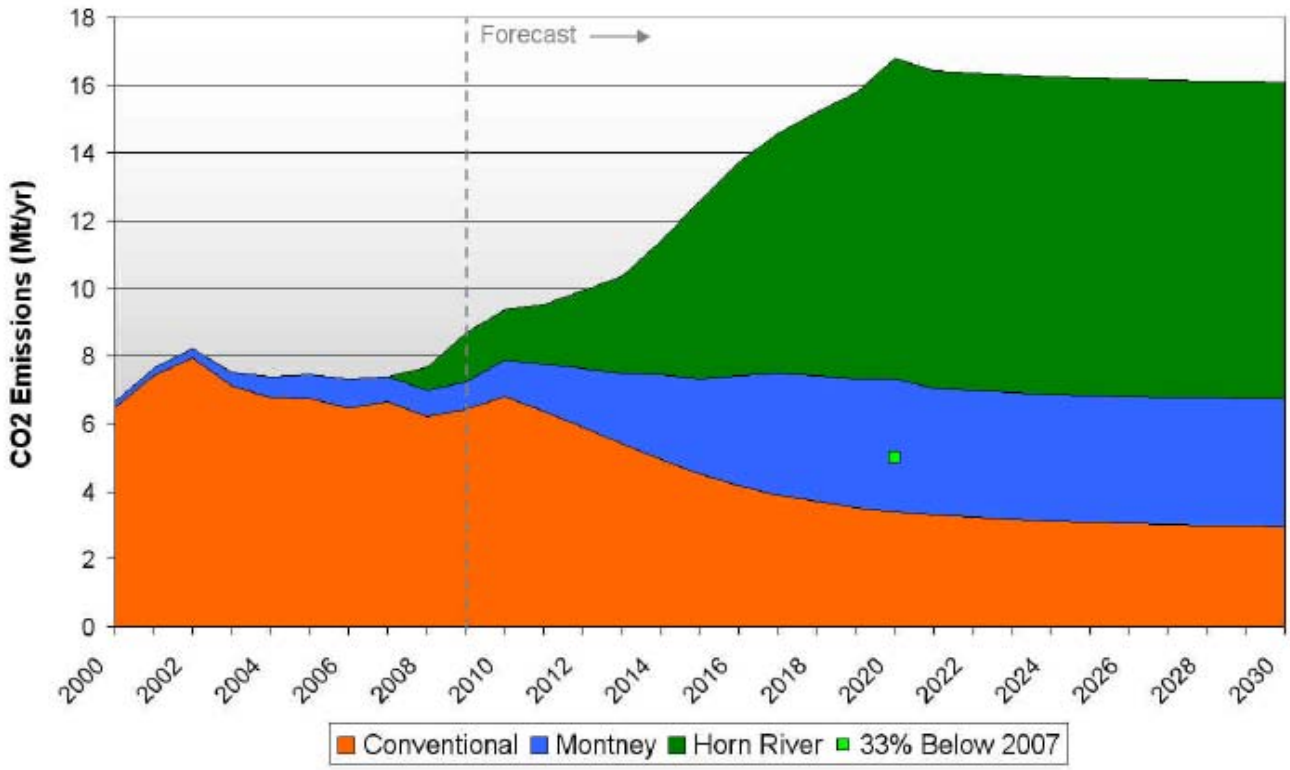
Montney Basin O&G	Notes	Units	Forecast 1 BCH BASE Forecast 2010 Load Forecast		Forecast 2 BCH HIGH Forecast 2010 Load Forecast		Forecast 4 CAPP Forecast Producers Forecast 2010	
			2017	2025	2017	2025	2017	2025
Gas Production Forecast	(1)	MMcf/d	2,698	3,312	4,706	5,320	3,700	4,300
Electric Intensity of Included Work	(2)	MW/MMcf/d	0.115	0.115	0.115	0.115	0.115	0.115
MW of Power for Included Work	(3)	MW	310	381	541	612	426	495
Load Factor	(4)	%	80.4%	80.4%	80.4%	80.4%	80.4%	80.4%
Annual Included Work Energy Required	(5)	GWh/yr	2,185	2,683	3,812	4,309	2,997	3,483
Electricity Forecast for BCH Service	(6)	GWh/yr	1,939	2,359	1,939	2,359	1,939	2,359
Implied Service/Electrification %	(7)	%	88.7%	87.9%	50.9%	54.7%	64.7%	67.7%
Net Un-Electrified Included Work Energy	(8)	GWh/yr	246	324	1,873	1,950	1,058	1,124
GHGs from Included Work Energy above	(9)	Mt/yr	1.31	1.61	2.29	2.59	1.80	2.09
GHGs from Excluded Work	(10)	Mt/yr	0.63	0.78	1.10	1.25	0.87	1.01
GHGs from Formation Gas, assuming 1.5%	(11)	Mt/yr	0.75	0.92	1.31	1.49	1.03	1.20
Total GHGs from Work and Formation Gas	(12)	Mt/yr	2.70	3.31	4.71	5.32	3.70	4.30
GHGs reduced by forecast BCH service	(13)	Mt/yr	1.16	1.42	1.16	1.42	1.16	1.42
Total GHGs after forecast BCH service	(14)	Mt/yr	1.53	1.90	3.54	3.90	2.54	2.88
% GHGs reduced by forecast BCH service	(15)	%	43.1%	42.7%	24.7%	26.6%	31.4%	32.9%

Notes

- **(9)** GHGs from Included Work Energy are based on gas-fueled compressors at 30% efficiency, ~600 T of CO2e /GWh of work done
- **(10)** GHGs from Excluded Work are back-calculated from line 12 - line 9 - line 11, Total GHGs - GHGs from Work Energy - GHGs from Formation Gas
- **(11)** GHGs from Formation Gas are estimated based on 1.5% of Gas Production, Line 1 x 51T/MMcf x 365 / 1,000,000
- **(12)** Total GHGs for Montney are based on 1 megaTonne CO2e/Bcf/d, estimated from charts in CAPP "BC's Energy Future", slides 3 & 5
- **(13)** GHGs reduced by proposed electrification are based on gas-fired compressors at 30% efficiency (~600 T/GWh) x the proposed work electrified (line 6)
- **(14)** Total GHGs after Electrification are the difference of line 12 - line 13
- **(15)** % GHGs reduced by proposed electrification is the ratio of line 13 / line 12

In this table, the total GHG emissions for Montney (line 12) have been estimated based on an October 2010 presentation by the Canadian Association of Petroleum Producers (CAPP) entitled "BC's Energy Future: Climate Policy and Energy Policy – Where do they meet?," which contained the following projection of CO_2 emissions for Montney Basin and Horn River Basin:

Figure 2.1-5 – CAPP Forecast of GHG Emissions for Montney and Horn River Basin[10]



This chart shows four Mt of CO_2 emitted at Montney by 2020. When combined with the load forecast for Montney of 4 billion cubic feet per day (Bcf/d) used in that presentation, this chart yields a total CO_2 emissions rate in 2020 of one Mt of CO_2 per Bcf/d. That factor was then used to calculate the corresponding emissions rates for each of the production forecasts in the table.

The CO_2 emission from formation gas was calculated, for each forecast, assuming 1.5% of the gas production was CO_2.[11] This gives an approximate estimate of the formation gas emissions from each forecast. GHGs from the 'excluded' work energy were subsequently back-calculated from the total CAPP estimate.

While this calculation of greenhouse gas emissions is very imprecise, it does indicate the massive scale of the greenhouse gas emissions associated with natural gas production. The accuracy of the component breakdown is not important, only indicative. The important emission amounts are the Total GHGs (line 12, taken from the CAPP presentation), and the GHGs reduced by the proposed electrification (line 13, based on the forecast service in the 2010 Load Forecast). These numbers together show the total amount of CO_2 emissions that will remain <u>after</u> the forecast level of BC Hydro service. This is an important guide to the effectiveness of the forecast level of BC Hydro service as a means of reducing overall GHGs and achieving the legislated GHG reduction targets.

Applied to the plausible-but-conservative CAPP forecast, a level of electrification analogous to that in BC Hydro's 2010 Load Forecast would reduce total greenhouse gas emissions by about 1.42 Mt but leave 2.88 Mt per year untouched in 2025. This is because the proposed level of electrification would only cover 68% of the 'included' work activities (67% of 2.09 Mt of CO_2), none of the 'excluded' work activities (with emissions of 1.01 Mt of CO_2), and none of the formation gas emissions (of 1.20 Mt of

CO_2). Consequently, the overall reduction of GHGs due to BC Hydro's assumed level of electrification would be only 32.9%.

Ways in which GHG reductions could be increased include:

a. Electrifying more of the 'Included' Work Energy demand, by connecting a greater percentage of sites to the grid,

b. Electrifying some of the 'Excluded' Work Energy demand (e.g. some of the drilling, fracturing, or pipeline compression), and/or

c. Implementing carbon capture and storage – using fully electrified compressors.

The additional electricity load from these three GHG reduction efforts is shown in Table 2.1-4 below.

Conclusion and Results

In order to calculate the total potential energy demand from Montney Basin shale gas activity, the study team adopted CAPP's forecast of gas production. The CAPP forecast is higher than BC Hydro's Base forecast, but is about 800-900 GWh more conservative than BC Hydro's High forecast. It is also about 2,200-2,700 GWh below the customer requests received to date.

Based on updating the forecast of gas production to the CAPP Forecast, the potential new load for Montney Basin activity is between 2,997 and 4,083 GWh in 2017 and between 3,483 and 4,742 GWh in 2025, depending on how much of the additional potential sites, work functions and intensity can be captured.

Table 2.1-4 – Summary of Potential New Electric Load for Montney

Montney Potential	**2017 GWh/yr**	**2025 GWh/yr**
Based on Forecast 4, Included Work Energy @ 0.115 intensity	2,997	3,483
Potential Electric Load is	**2,997**	**3,483**
This can be further augmented by adding:		
a) add 30% of 'excluded' work functions	434	505
b) 13% higher intensity on 'included' work functions	390	450
c) 5% higher service percentage	150	175
d) implement electrified CCS	111	129
Total Potential Electric Load	**4,083**	**4,742**
Relative to the BASE Forecast from the 2010 Load Forecast	1,939	2,359
Net Potential New Electric Load is	**2,144**	**2,383**

The Net Potential New Load (in excess of the 2010 Load Forecast) is up to 2,144 GWh in 2017 and 2,383 GWh in 2025.

The BC Hydro 2010 Load Forecast includes a load growth projection for the Montney Basin. Chapter 3 below gives more detail on the load that BC Hydro has forecast for the Montney Basin, for comparison with the above forecast.

End Notes:

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[1] BC Hydro. *Electric load forecast 2010/11 to 2030/31: load and market forecast (2010 forecast)*. Prepared by BC Hydro Energy Planning and Procurement, Customer & Corporate Services. 2010. p.97

[2] BC Hydro: "Synergies and inter-relationships between natural gas and electricity development." PowerPoint presentation by Doug Little to the BC Natural Gas Symposium, June 1, 2011. Slide 10

[3] Email June 28, 2011 from BC Hydro's Doug Little in response to Steve Davis prior email titled "Clarification questions on your Montney load forecast and HRB GHGs" – Question #2.

[4] BC Hydro. *Application for its Dawson Creek/Chetwynd Area Transmission Project*. Application to BC Utilities Commission, filed July 11, 2011. App. B, p. 82 of 100.

[5] BC's Energy Future. *Climate Policy and Energy Policy – Where do they meet?* Presentation by CAPP President Dave Collyer to BCBC & BC Chamber of Commerce BC Energy Conference. October 27, 2010. Slide 10.

[6] BC Hydro. *2010 forecast*. p. 99.

[7] ibid. p. 98.

[8] Email June 28, 2011 from BC Hydro's Doug Little in response to Steve Davis prior email titled "Clarification questions on your Montney load forecast and HRB GHGs" – Question #3.

[9] op cit. p.99.

[10] CAPP. "BC's Energy Future: Climate Policy and Energy Policy – Where do they meet?" PowerPoint presentation given by the President of CAPP. October 27, 2010. Slide 10.

[11] BC Hydro staff confirmed at the July 20, 2011 workshop on the Dawson Creek/Chetwynd Area Transmission Project that 1.5% formation gas is typical of the Montney shale gas deposits.

2.2 Sector # 2: Horn River Basin Shale Gas Activity

This section describes the Mid Case forecast of potential new electricity load required by natural gas activities in the Horn River Basin. It includes a background introduction, a review of gas production forecasts by BC Hydro, CAPP and TransCanada, the conversion of those gas production forecasts to electricity load requirements, the identification and quantification of elements that affect the breadth and depth of electrification, and the impact of GHG emissions and policies on electrification.

Background:

The Horn River Basin ("Horn River" or "HRB") is a region of shale gas development located approximately 90 km north of Fort Nelson. The industry's high opinion of this region's shale gas production potential is demonstrated by the large number of major oil and gas development companies committing significant investment resources to acquiring land holdings and exploration rights.

The rapid development of this gas basin is being driven by the new technology for horizontal drilling and hydraulic fracturing that makes production from shale formations economically viable. Gas company heat and power needs have traditionally been met by natural gas and/or diesel generators and compressors, but clean electrical energy could be used by processing plants and for compression in gathering systems and pipelines, and could ultimately be extended to drill rigs and hydraulic fracturing compressors.

Since the BC Hydro transmission grid does not currently connect to Fort Nelson, this area is referred to by the utility as the Non-Integrated Area (NIA). The town's electricity comes from local gas-fired generation (currently being expanded to 75 MW), with some backup provided by a minor transmission connection to Alberta. The current supply of electricity will not be sufficient to serve the expected new HRB load, and so BC Hydro is evaluating the feasibility of extending service to Fort Nelson and then to a new substation near the centre of the Horn River Basin gas activities. This potential transmission extension is referred to as the Northeast Transmission Line (NETL).

BC Hydro has included a minimal forecast of load in Fort Nelson and the Horn River Basin as part of its 2010 Load Forecast for the Non-Integrated Area, showing 1,092 GWh by the year 2025.[1] This amount is far less than the actual work energy that will be required to achieve the gas production forecasts for the area. The study team believes that this low forecast number likely reflects BC Hydro's uncertainty over whether the NETL transmission line will be built and, if so, when.

There is a tremendous potential to increase Industrial loads in this area if the NETL is built at an early enough date to allow the shale gas development to be electrified. However, if a commitment to electrification, and the extension of the BC grid to the Ft. Nelson/HRB region is not done in a timely manner, the industry will meet its growing energy demand through the self-supply of natural gas and diesel-fuelled energy, which will produce a significant increase in the provincial GHG emissions.

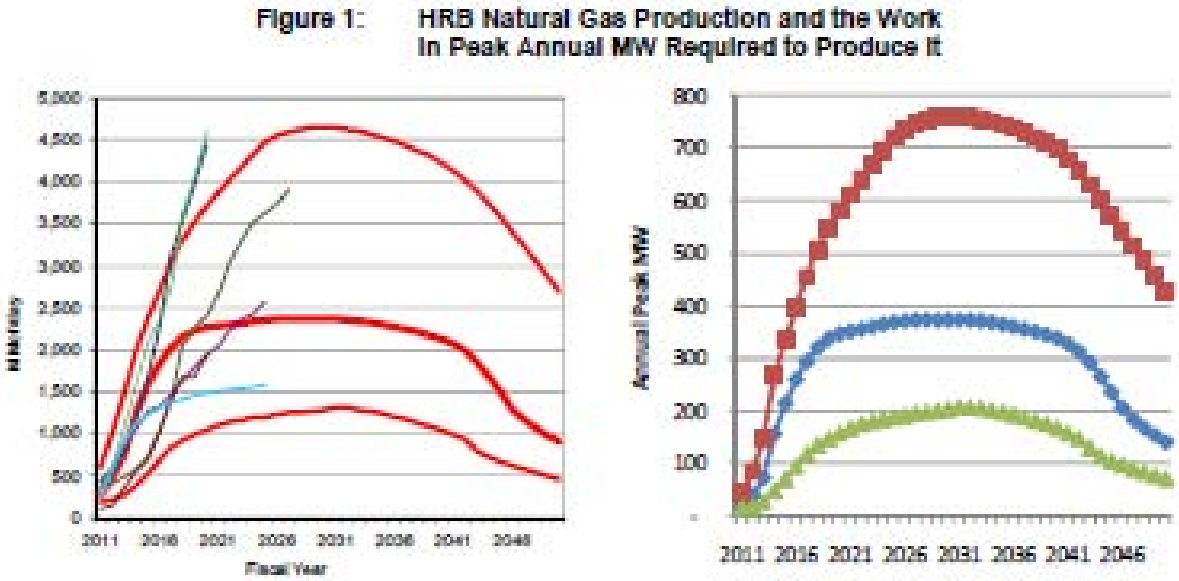
As in the Montney Basin (see Section 2.1 above), the electrical loads in the Horn River Basin have the potential to increase dramatically for several reasons:

- Increased gas production forecasts (as indicated by increased customer requests for service);
- Broadening the range of functions to be electrified; and
- Increasing the penetration of electrical service within those functions that can be electrified.

BC Hydro Gas Production Forecasts

In its 2011 Integrated Resource Plan, BC Hydro presented the following charts depicting Low, Mid and High forecasts of gas production from the Horn River Basin, and the corresponding peak MW required to achieve these levels of gas production (see Figure 2.2-1 below). BC Hydro's Mid forecast is the one that was used for the BC Hydro December 2010 Load Forecast.

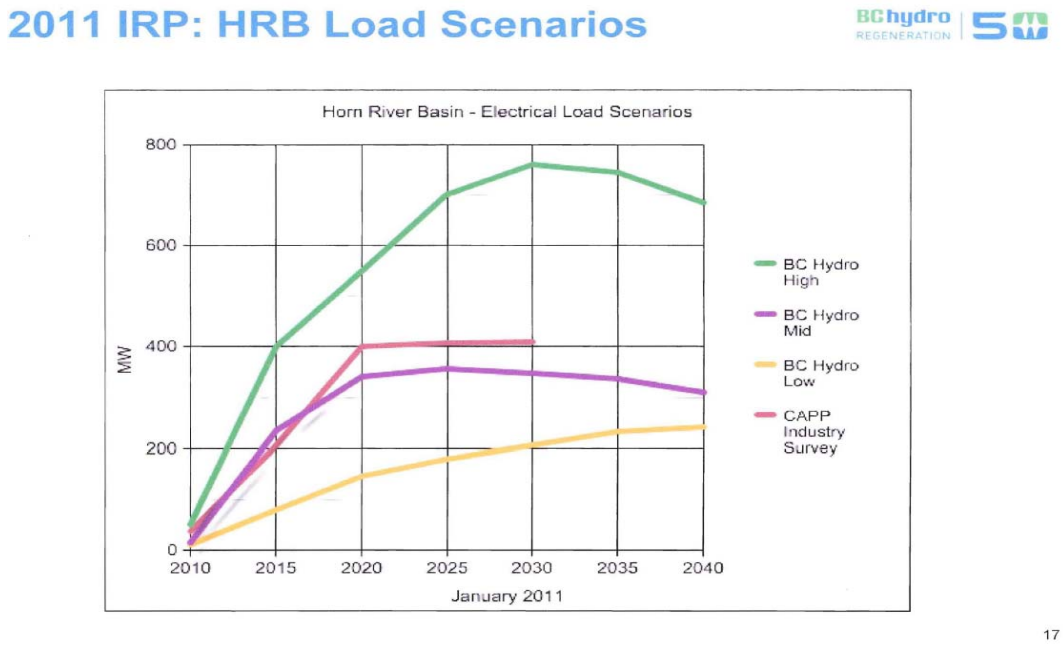
Figure 2.2-1 – BC Hydro Gas Production Forecasts and Work Requirements[2]



The charts indicate that in 2025, BC Hydro's Low, Mid, and High case levels are about 1,300 million cubic feet per day (MMcfd), 2,300 MMcfd and 4.6 MMcfd respectively, so that the high case is 250% of the low case projection. These charts were also used to derive BC Hydro's assumptions about the electricity intensity of shale gas production from the HRB in terms of MW per MMcfd. The electric intensity being used by BC Hydro appears to be about 0.165 MW/MMcfd, which is much higher than the 0.115 MW/MMcfd rate used in Montney. (It is not clear why BC Hydro has used a higher intensity for Horn River than for Montney, but the consequence is an increase in the potentially electrifiable work energy).

BC Hydro staff also presented Horn River Basin load scenarios in a presentation to the BC Gas Symposium in June 2011 (see Figure 2.2-2 below, which is slide 17 of that presentation.).

Figure 2.2-2 – BC Hydro Horn River Scenarios from the 2011 IRP[3]



The capacity (or MW) values on this Load Scenario chart are materially the same as the values on the upper right hand chart of Figure 2.2-1 above, except that the Low forecast does not decline after 2030.

The Mid and High BC Hydro scenarios have been incorporated into the following table, along with two other recent forecasts from industry for comparison purposes.

Table 2.2-1 – BC Hydro BASE and HIGH Forecasts, plus TransCanada and CAPP Forecasts

Major Load Potential #2 - Horn River Basin Oil & Gas

Horn River Basin O&G			Forecast 1 BCH BASE Forecast 2010 Load Forecast		Forecast 2 BCH HIGH Forecast 2010 Load Forecast		Forecast 3 TransCanada Pipelines Forecast June, 2011		Forecast 4 CAPP Producers Forecast 2010	
	Notes	Units	2017	2025	2017	2025	2017	2025	2017	2025
Gas Production Forecast	(1)	MMcf/d	1,824	2,308	3,000	4,500	1,800	3,100	2,000	2,650
Electric Intensity of Included Work	(2)	MW/MMcf/d	0.164	0.165	0.155	0.167	0.164	0.165	0.164	0.165
MW of Power for Included Work	(3)	MW	300	380	465	750	296	510	329	436
Load Factor	(4)	%	80.4%	80.4%	80.4%	80.4%	80.4%	80.4%	80.4%	80.4%
Annual Included Work Energy Required	(5)	GWh/yr	2,113	2,676	3,275	5,282	2,085	3,595	2,317	3,073
Energy Proposed for BCH Service	(6)	GWh/yr	892	1,092	892	1,092	892	1,092	892	1,092
Implied Service/Electrification %	(7)	%	42.2%	40.8%	27.2%	20.7%	42.8%	30.4%	38.5%	35.5%
Net Un-Electrified Included Work Energy	(8)	GWh/yr	1,221	1,584	2,383	4,190	1,193	2,503	1,425	1,981

Notes

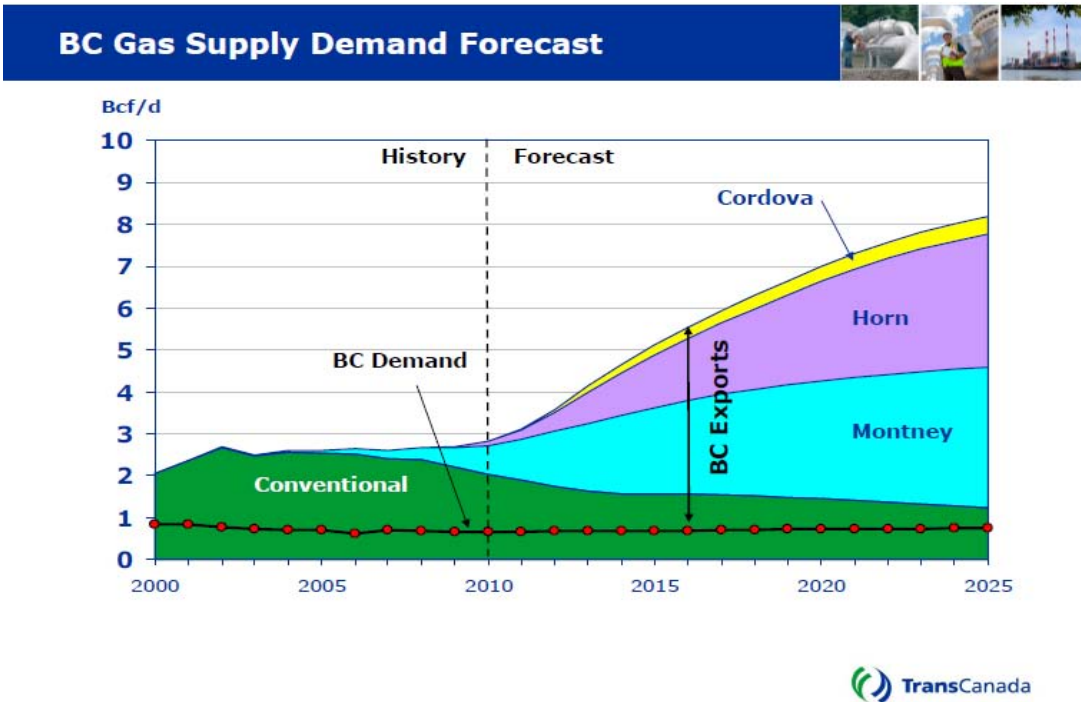
(1) For Forecast 1, Gas Production is input from 2010 Load Forecast, Appendix 3.2, Table A3.1, Non-Integrated Area (Fort Nelson)
For Forecast 2, Gas Production is estimated from Fig. 1 of BC Hydro's Summary Brief to the 2011 IRP
For Forecast 3, Gas Production is estimated from slide 7 of TransCanada's presentation to the BC Gas Symposium, May 31, 2011, titled "BC Gas Supply Demand Forecast"
For Forecast 4, Gas Production is estimated from chart "CAPP BC Production Forecast", late 2010

(2)	For Forecasts 1 and 2, the Intensity is back-calculated from the data derived for lines 1 and 3. Forecasts 3 and 4 are given the same Intensity as Forecast 1 Electric Intensity is the power in MW required to drive the included work processes, needed to achieve a gas production rate in millions of cubic feet per day Included Work processes are those viewed as most readily electrifiable, such as moving the gas from the RGTs to the processing plant but not the drilling, fracturing or new pipeline loads
(3)	For Forecasts 1 and 2, MW of Power Required is estimated from Fig. 1 of BC Hydro's Summary Brief to the 2011 IRP TAC, "Electrification of the Horn River Basin" For Forecasts 2 and 3, Power is estimated from BC Hydro's chart "Dawson Creek and Groundbirch Load Forecast" / 0.85 Dawson Creek and Groundbirch is assumed to comprise 85% of the total Montney production potential (per D. Little of BCH)
(4)	A Load Factor of 80.4% is used for all forecasts, based on the value used in BCH's DCAT Application, Appendix B, page 82 of 100, to convert 275 MW to 1,938 GWh in F2025
(5)	Annual Work Energy Required (in GWh) is calculated from Power (in MW) x Load Factor x 8,760 hr / 1,000
(6)	Energy Proposed for BC Hydro Service is the amount shown in the 2010 Load Forecast, Appendix 3.2, page 94, Table A3.1
(7)	The Implied Service/Electrification % is the proportion of the Annual Included Work Energy that BCH is forecasting to service in its 2010 Load Forecast
(8)	The Net Un-Electrified Work Energy is the balance of the Included Work Energy that must be obtained from other sources, most likely fossil fuels

The two gas industry forecasts included in Table 2.2-1 above were derived from the following charts, taken from recent public presentations:

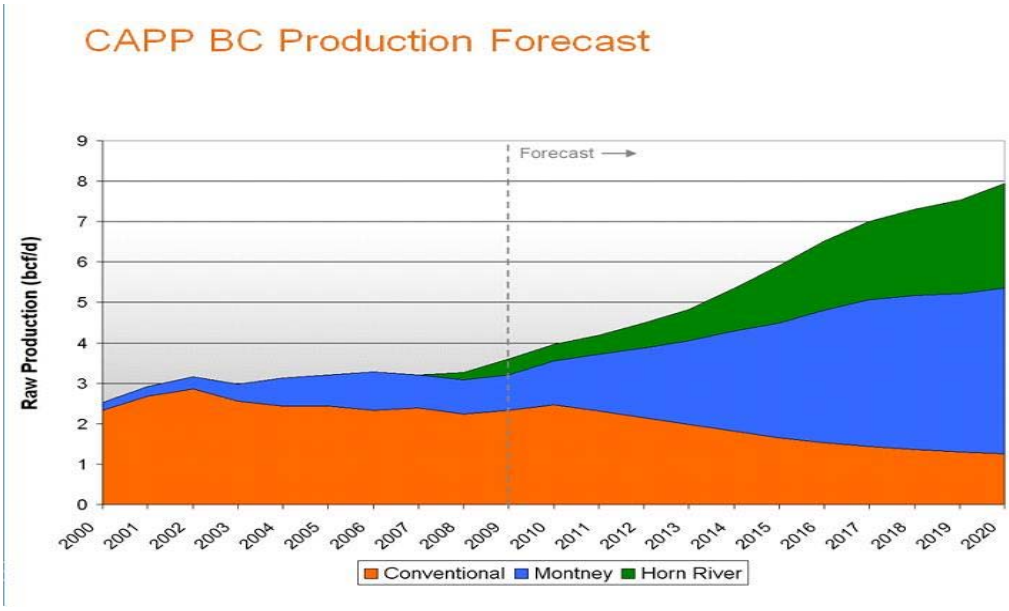
Forecast 3 was taken from a presentation by TransCanada.

Figure 2.2-3 – TransCanada Production Forecast for Montney and Horn River Basins[4]



Forecast 4 was taken from the same CAPP forecast as was used in the Montney analysis:

Figure 2.2-4 – CAPP Production Forecast for Montney and Horn River Basins[5]



The gas production values in Table 2.2-1 were estimated from the graphical areas shown on these charts. Other values were calculated using the assumptions described in the Notes accompanying this Table.

For the purposes of this report, the study team decided to use and an average of the TransCanada forecast of June 2011 (Forecast 3) and the CAPP production forecast of 2010 (Forecast 4), as shown in Table 2.2-1 above. This provides a plausible, but still conservative, updated estimate of the future gas production activity in the Horn River Basin area.

In terms of gas production, the average of the two industry forecasts is considerably lower than BC Hydro's High forecast for 2017, but is very close to BC Hydro's Base forecast for 2017 (1,900 MMcf/d vs. 1,824 MMcf/d respectively). By 2025, however, the average of the two industry forecasts is about 25% higher than BC Hydro's BASE forecast (2,875 MMcf/d vs. 2,308 MMcf/d respectively).

Not surprisingly, the forecast of annual 'Included' Work Energy follows the same pattern: while the average of the two forecasts is only marginally above the BC Hydro forecast in 2017, it is about 25% higher by 2025, as shown in the following table:

Table 2.2-2

Included Work Energy is very comparable between industry and BC Hydro forecasts

Included Work Energy Required		2017 GWh/yr	2025 GWh/yr
Based on an average of Forecast 3 and Forecast 4		2,201	3,334
Relative to BC Hydro BASE Forecast of Work Energy		2,113	2,676
Additional Potential Load is	GWh	**88**	**657**
	% difference	4%	25%

All of the work energy that has been calculated as 'Included' Work Energy, using BC Hydro's ratio of electric intensity of 0.165 MW/MMcfd, can be electrified and therefore constitutes the first foundation of potential electric load.

However, for reasons that are not apparent, BC Hydro's 2010 Load Forecast contains only enough electric load to electrify about 40% of that 'Included' Work Energy (See line 7 of Table 2.2-1).

Table 2.2-3

However, forecast of electric service is considerably lower than Work Energy required

Work Energy compared to Electrification		2017 GWh/yr	2025 GWh/yr
Included Work Energy (average of Forecast 3 and 4)		2,201	3,334
Forecast of electric service from the 2010 Load Forecast		892	1,092
Additional Potential Load is	GWh	**1,309**	**2,242**
BC Hydro forecast electric service as % of Work Energy		41%	33%

Furthermore, as in the case of Montney, gas production activity is only one factor in determining the amount of potential electrical energy load. Other factors which can have a significant effect on the electrical load include:

a) The amount of 'Included' Work - the functions considered eligible to be electrified:

BC Hydro bases its electrical load forecast on the assumption that only certain functions will be electrified and only at a certain fraction of the sites. For instance, BC Hydro's 2010 Load Forecast[6] states that the drilling and hydraulic fracturing operations would not be electrified, that electricity demand for water recycling tasks would not be significant, and that new pipeline loads would not be electrified.

The electricity for these activities is currently being provided by diesel generators. If government policy required companies to switch to using clean electricity from the grid, and if the transmission grid was extended to these facilities, these could become additional new loads.

b) The intensity of the use of electricity to perform the 'Included' Work:

The term 'intensity' is used to describe the amount of electricity required for each unit of gas produced. This is largely a function of which work activities are 'included' as potentially electrifiable, but it does not include all of the work activities.

BC Hydro's 2010 Load Forecast used an intensity of 0.115 MW/MMcfd for the Montney region activities. However, for the Horn River Basin activities, it appears that BC Hydro uses a higher intensity of 0.164 MW/MMcfd to 0.165 MW/MMcfd.[7]

Given this higher intensity, this report refrains from adding a further increment to arrive at the potential new load.

c) Service Percentage:

Once the potentially electrifiable activities are estimated, then that energy is multiplied by factor referred to as the 'service percentage.' The service percentage is the proportion of potentially electrifiable energy to be provided service by BC Hydro. The limitations placed on providing service may be due to the geographic location of the load, or the timing of available transmission, or other unstated factors. In the case of the Horn River Basin activities, since we are recommending that the full amount of the 'Included' Work Energy form the basis of the potential new electric load, it is not necessary to further increase the service percentage.

GHG Emissions

Increased gas production at Horn River results in not only increased electricity demand, but also increased GHG emissions. Increased emissions run counter to the provincial government's GHG Reduction Targets Act and international agreements, and could trigger significant future carbon-related costs or liabilities to the province and/or to the emitters.

As with Montney, maximizing the amount of Horne River Basin activities driven by clean electricity from BC Hydro's grid will reduce emissions compared to the use of diesel or gas-fuelled generators. In addition to the environmental benefits, reducing GHG emissions promises to deliver significant financial savings as costs on carbon increase over time, and are applied to a broader range of emission sources. As such, GHG emissions impact both the amount and the economics of electricity load growth.

Ways in which the GHGs reductions could be increased include:

- expanding the extent of the area serviced by the grid (i.e. the Service Percentage),
- increasing the number of work activities that are electrified (i.e. the Work Included) and
- increasing the degree of electrification of those activities (i.e. the Intensity).

As shown in the following table, the amount of electrification forecast in the 2010 Load Forecast will reduce the GHG emissions from the Horn River shale gas activities by only about 5% and will leave untouched 10 to 14 million tonnes (i.e. Mt) of new GHG emissions by 2025. Such an outcome would render it virtually impossible to meet the legislated GHG reduction target of 22 Mt by 2020.[8]

The majority of these residual GHG emissions comes from the venting of formation CO_2 and could be prevented by implementing carbon capture and sequestration (as the government has directed for coal-fired generators). However, even if all of the 'Included' Work Energy is electrified, there would still be a considerable amount of CO_2 being emitted by the 'Excluded' Work Energy.

Table 2.2-4 - Forecasts 1, 2, 3, and 4, showing Greenhouse Gas (GHG) Consequences

Major Load Potential #2 - Horn River Basin Oil & Gas

Horn River Basin O&G	Notes	Units	Forecast 1 BCH BASE Forecast 2010 Load Forecast		Forecast 2 BCH HIGH Forecast 2010 Load Forecast		Forecast 3 TransCanada Pipelines Forecast June, 2011		Forecast 4 CAPP Producers Forecast 2010	
			2017	2025	2017	2025	2017	2025	2017	2025
Gas Production Forecast	(1)	MMcf/d	1,824	2,308	3,000	4,500	1,800	3,100	2,000	2,650
Electric Intensity of Included Work	(2)	MW/MMcf/d	0.164	0.165	0.155	0.167	0.164	0.165	0.164	0.165
MW of Power for Included Work	(3)	MW	300	380	465	750	296	510	329	436
Load Factor	(4)	%	80.4%	80.4%	80.4%	80.4%	80.4%	80.4%	80.4%	80.4%
Annual Included Work Energy Required	(5)	GWh/yr	2,113	2,676	3,275	5,282	2,085	3,595	2,317	3,073
Electricity Forecast for BCH Service	(6)	GWh/yr	892	1,092	892	1,092	892	1,092	892	1,092
Implied Service/Electrification %	(7)	%	42.2%	40.8%	27.2%	20.7%	42.8%	30.4%	38.5%	35.5%
Net Un-Electrified Included Work Energy	(8)	GWh/yr	1,221	1,584	2,383	4,190	1,193	2,503	1,425	1,981
GHGs from Included Work Energy above	(9)	megaT/yr	1.27	1.61	1.97	3.17	1.25	2.16	1.39	1.84
GHGs from Excluded Work	(10)	megaT/yr	3.32	4.20	5.58	8.15	3.28	5.64	3.64	4.82
GHGs from Formation Gas, assuming 12%	(11)	megaT/yr	4.07	5.16	6.70	10.05	4.02	6.92	4.47	5.92
Total GHGs from Work and Formation Gas	(12)	megaT/yr	8.66	10.96	14.25	21.38	8.55	14.73	9.50	12.59
GHGs reduced by forecast BCH service	(13)	megaT/yr	0.54	0.66	0.54	0.66	0.54	0.66	0.54	0.66
Total GHGs after forecast BCH service	(14)	megaT/yr	8.13	10.31	13.71	20.72	8.01	14.07	8.96	11.93
% GHGs reduced by forecast BCH service	(15)	%	6.2%	6.0%	3.8%	3.1%	6.3%	4.4%	5.6%	5.2%

Detailed notes for lines 1 to 8 are the shown in the Notes for Table 2.2.1.

Notes

(9) GHGs from Included Work Energy are based on gas-fueled compressors at 30% efficiency, ~600 T of CO2e /GWh of work done

(10) GHGs from Excluded Work are back-calculated from line 12 - line 9 - line 11, Total GHGs - GHGs from Work Energy - GHGs from Formation Gas

(11) GHGs from Formation Gas are estimated based on 12% of Gas Production, Line 1 x 51T/MMcf x 365 / 1,000,000

(12) Total GHGs for HRB are based on 4.75 megaTonnes CO2e/Bcf/d, estimated from charts in CAPP "BC's Energy Future", slides 3 & 5

(13) GHGs reduced by proposed electrification are based on gas-fired compressors at 30% efficiency (~600 T/GWh) x the proposed work electrified (line 6)

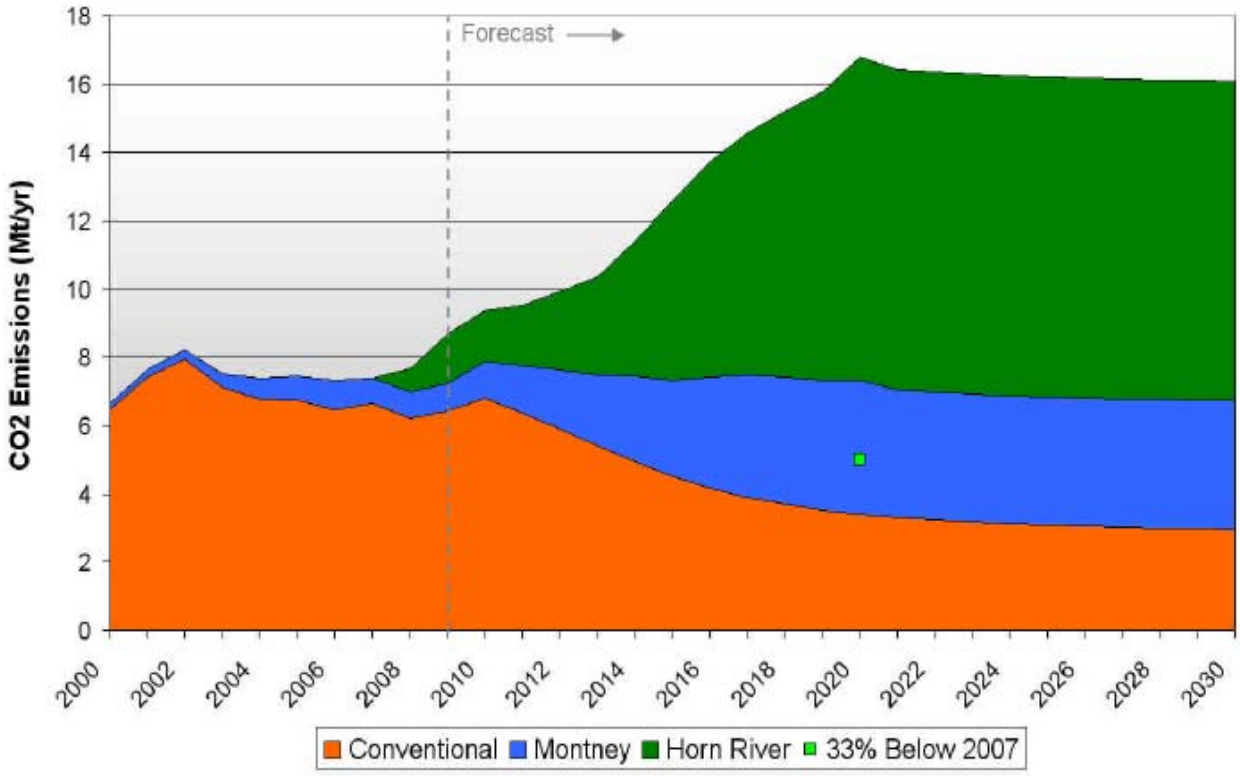
(14) Total GHGs after Electrification are the difference of line 12 - line 13

(15) % GHGs reduced by proposed electrification is the ratio of line 13 / line 12

The information on GHG emissions shown in Table 2.2-4 above is derived from data presented by CAPP in 2010 (see Figure 2.2-5 below).

The total GHG emissions for Horn River Basin (line 12) were estimated based on the following chart from the CAPP presentation, and the values in the preceding lines were then back-calculated.

Figure 2.2-5 – CAPP GHG emissions forecast for natural gas production in BC. [9]



This chart indicates that approximately 9.5 Mt of CO_2 would be emitted from the Horn River Basin shale gas operation in 2020. When combined with the load forecast for Horn River of 2 Bcf/d used in that presentation, this chart yields a total CO_2 emissions rate in 2020 of 4.75 Mt of CO_2 per Bcf/d. That emissions rate was then used to calculate the corresponding emissions rates for each of the production forecasts in the table.

The CO_2 emissions from the Horn River Basin formation gas were calculated, for each forecast, assuming that 12% of the gas produced at the wellhead was CO_2.[10] This gives an approximate estimate of the formation gas emissions from each forecast. Then the only missing element is the GHGs from the 'Excluded' Work Energy, which is back-calculated from the total.

The important emission amounts are the Total GHGs (line 12, taken from the CAPP presentation), and the GHGs reduced by the proposed electrification (line 13, based on BC Hydro's proposed electrification in the 2010 Load Forecast). The precise breakdown of the components is not important, only indicative. These numbers together show the total amount of CO_2 emissions that will remain <u>after</u> the proposed electrification. This is an important guide to the effectiveness of the proposed levels of electrification as a means to reducing overall GHGs and achieving the legislated GHG reduction targets.

For instance, for Forecast 4 (the CAPP forecast, considered plausible but conservative by the study team) the forecast of electric service (in BC Hydro's 2010 Load Forecast) will produce a GHG reduction of only about 0.66 Mt, but leave 11.93 Mt per year untouched in 2025. This is because the forecast level of electric service would only cover 35% of the 'Included' work activities (35% of 1.84 Mt of CO_2), none of the 'Excluded' work activities (with emissions of 4.82 Mt of CO_2) and none of the formation gas emissions (of 5.92 Mt of CO_2). Consequently the overall reduction of GHGs that would occur at BC Hydro's proposed level of electrification is only 5.2%.

The three ways to increase this percentage of GHG reduction are to:

- Electrify more of the 'Included' Work Energy demand, by connecting a greater percentage of sites to the grid,
- Electrify some of the 'Excluded' Work Energy demand (e.g. some of the drilling, fracturing, or pipeline compression), and/or
- Implement carbon capture and storage technology using fully electrified compressors.

The above analysis shows that there will be many megatonnes (Mt) of annual CO_2 emissions from Horn River Basin activities under the future envisaged in BC Hydro's 2010 Load Forecast. These emissions, however, could be significantly reduced by an aggressive push for electrification using emission-free grid electricity.

Conclusion and Results:

The range of additional load potential that should be possible in the Horn River Basin is summarized in Table 2.2-5 below. The foundation of the potential load is based on updating the forecast gas production to the average of the TransCanada and CAPP forecasts. The study team suggests that considerable additional electricity loads are possible if an additional 20% of the 'excluded' work functions can be electrified, and if carbon capture and sequestration (CCS) is implemented and electrified.

Depending on how much of the additional potential work functions are electrified and whether CCS is implemented and electrified, the potential new load for the Horn River Basin shale gas activity increases by between 1,300 GWh and as much as 2,900 GWh in 2017 and between 2,200 and 4,700 GWh in 2025.

Table 2.2-5

Potential New Electric Load for Horn River Basin Activities	2017 GWh/yr	2025 GWh/yr
Included Work Energy (average of Forecast 3 and 4)	2,201	3,334
Potential Electric Load is	**2,201**	**3,334**
This can be further augmented by adding:		
a) add 20% of 'excluded' work functions	1,153	1,745
b) implement electrified CCS	458	693
Total Potential Electric Load	**3,812**	**5,771**
Relative to the BASE Forecast from the 2010 Load Forecast	892	1,092
Net Potential New Electric Load is	**2,920**	**4,679**

End Notes:

[1] BC Hydro. *2010 load forecast*. 2010. Appendix 3.2, Table A3.1.

[2] BC Hydro. Integrated Resource Plan Technical Advisory Committee meeting #3. PowerPoint deck. February 14, 2011. Slide 6. The Mid-line on the production chart conforms to the numbers in Table A3.1 in Appendix 3.2 in that 2010 Load Forecast.

[3] BC Hydro. presentation to the BC Gas Symposium. June 2011. Slide 17.

[4] Source: TransCanada (Pipelines). PowerPoint presentation to BC Gas Symposium, May 31, 2011.

[5] CAPP. "BC's Energy Future: Climate Policy and Energy Policy – Where do they meet?" Slide 10.

[6] BC Hydro. *2010 load forecast*. 2010. p. 99.

[7] Inferred from the charts in Figure 2.2-1.

[8] The government has legislated that province-wide GHG emissions must be reduced to 33% below 2007 levels by 2020. This means a reduction from about 68 megaTonnes per year in 2007 to about 46 megaTonnes per year by 2020. An increase of 10-14 Mt in one industry sector would negate up to 64% of the savings achieved by all other sectors. Note that these emissions do not include the eventual combustion of the natural gas, most of which will take place outside of BC. These emissions only include the GHGs emitted within BC in the production or transmission of the gas, by the burning of fossil fuels or the venting of formation gas.

[9] CAPP. "BC's Energy Future: Climate Policy and Energy Policy – Where do they meet?" Slide 10.

[10] The Horne River Basin is remarkable for producing natural gas with 12% CO_2 content. By contrast, shale gas from other regions typically contain only 1 or 2% CO_2.

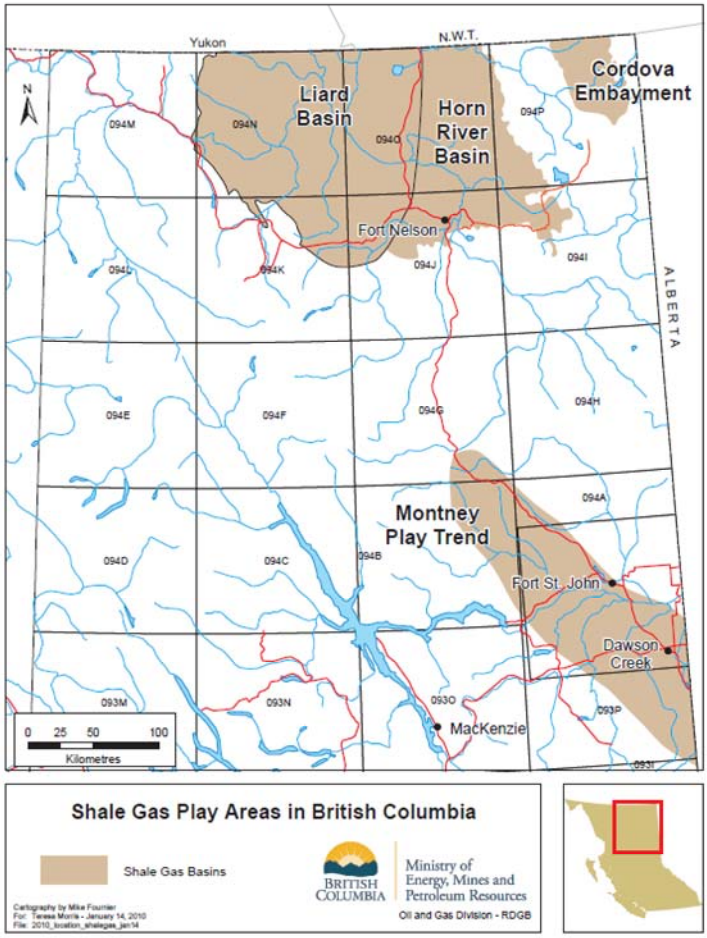
2.3 Sector # 3: Liard Basin and Cordova Embayment Shale Gas Activity

This chapter describes the Mid Case forecast of potential new electricity load required by natural gas activities in the Liard Basin and Cordova Embayment gas fields. It includes a background introduction, the calculation behind a gas production forecast, and the conversion of that gas production forecast to an electricity load requirement.

Background

The Liard Basin and Cordova Embayment gas fields are adjacent to the Horn River Basin, but are much less explored. They are located west and northeast of Horn River, and are now being explored and developed for extraction as a result of new shale gas production technology. Like the Fort Nelson/HRB area, this area is not connected to BC Hydro's grid (referred to as the Non-Integrated Area, or NIA). These fields are still in early development stages, but will need energy to perform the same functions as in the Horn River and Montney Basins. The map below shows the location of these areas relative to the Montney and Horn River Basins.

1. **Figure 2.3 – 1 Map of Northeast Gas Basins**[1]

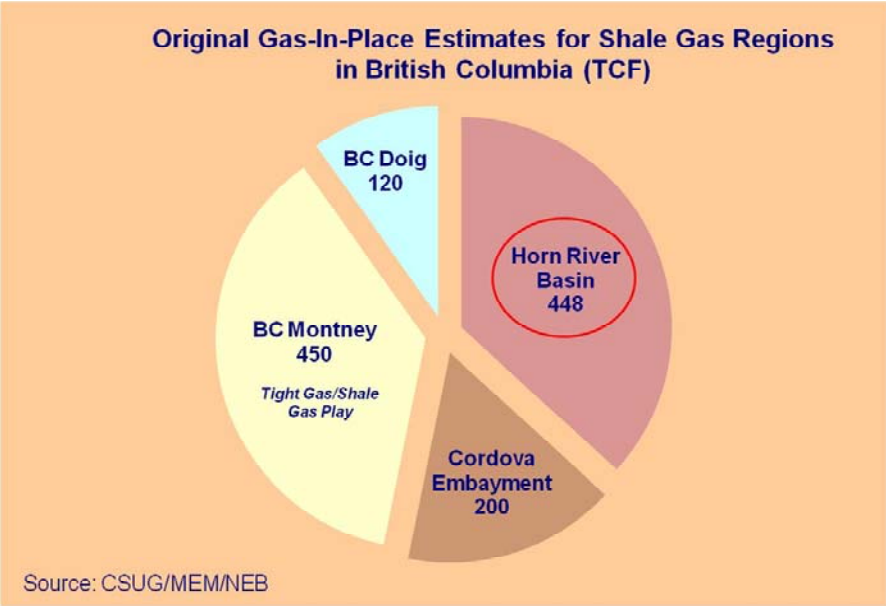


The Liard Basin and Cordova Embayment are relatively new. Their characteristics are generally similar to the adjacent Horn River Basin, but they are several years behind in terms of investigation and production.

Forecasting gas production potential:

Insufficient exploration has taken place to make definitive gas production forecasts for Liard Basin and Cordova Embayment at this point. Early investigations indicate that the scale of the gas in place within the Cordova Embayment is significant (see Figure 2.3 below).

Figure 2.3 – 2 Original Gas-in-Place Estimates for Three Northeast Gas Basins[2]



The geologic structures of these basin areas are similar and the land area of the Liard Basin is similar to the Horn River Basin:

	Hectares (millions)
Montney Basin	**1.5**
Horn River Basin	**1.3**
Liard Basin (1.25 million hectares) **+ Cordova Embayment** (0.4 million hectares)	**1.65**

While BC Hydro did not include any additional forecast load specifically for the Liard and Cordova Embayment areas in its 2010 Load Forecast, gas companies are now investing significantly in acquiring land holdings and in exploratory drilling. If those results continue to show promise and this basin starts to develop like the Horn River Basin, there will be significant new potential load requirements.

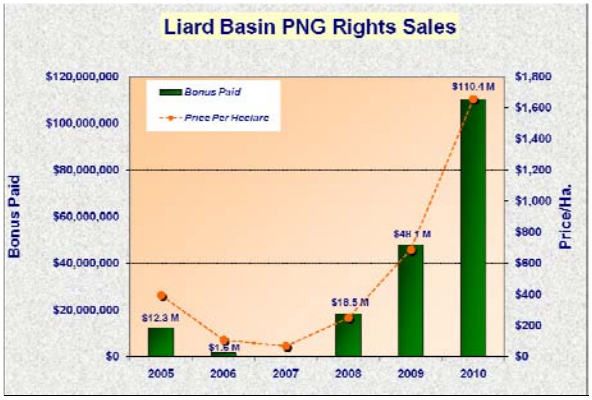
Since these areas are adjacent to the HRB but further away from the transmission grid, any interconnection would rely on first extending the grid to Horn River and then extending it further to Liard and Cordova.

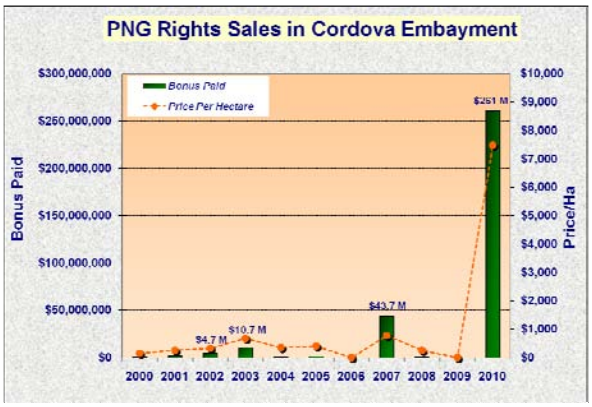
It is therefore reasonable to expect that the gas production potential for Liard Basin and Cordova Embayment should be similar to that of the Horn River Basin. However, activity there will lag a number of years behind Horn River Basin.

There was enormous interest in the Montney and Horn River regions between 2006 and 2009, with the Liard and Cordova regions waiting until 2010 to be seriously explored.

The following charts indicate how the payments to the province for petroleum and natural gas rights in Liard and Cordova were delayed relative to the payments for Montney and Horn River.

Figure 2.3 – 3 Petroleum and Natural Gas Rights Sales in Northeast Gas Basins[3]





Forecast of Electricity Load

Since reliable gas production forecasts for the Liard and Cordova areas are not yet available, the only way to even roughly forecast future electricity loads is to assume they will be proportional to the size of their gas potential relative to other similar nearby basins.

Since the areas of the Liard Basin and Cordova Embayment are approximately the same size as the Horn River Basin, and the characteristics are similar, it can be expected that the gas potential will also be similar. However, the charts of petroleum and natural gas rights sales show that the interest in Liard and Cordova in 2010 is more similar to the interest in Montney in 2006 or Horn River in 2007. It is reasonable to expect, therefore, that there will be a delay of at least three to four years in the development of Liard and Cordova.

Because these two regions are more remote, requiring longer extension of infrastructure, including pipelines and electrical transmission, this report makes the more conservative assumption that the delay will be eight years relative to the Horn River production development. To be even more conservative, and in line with the partial information available through existing resource assessments, this report also assumes that the combined Liard and Cordova Embayment areas **will only produce at one-half the rate of the similarly sized Horn River Basin.**.

In the previous section, the potential new load for Horn River Basin activity was forecast to be 2,201 GWh in 2017. That figure is used as the foundation of the potential new electric load for Liard and Cordova eight years later, in 2025. Since the 2010 Load Forecast contains zero for these areas, the entire amount is potential new load. The new load is calculated in Table 2.3-1 below.

Table 2.3-1 – Liard and Cordova production assumed to be 1/2 of Horn River and delayed 8 years

Estimates for Liard and Cordova Basin Activities	2017 GWh/yr	2025 GWh/yr
Estimate based on 50% of Horn River Basin delayed by 8 years	-	1,100
Foundation of Potential New Electric Load is	**-**	**1,100**
This can be further augmented by adding:		
a) add 20% of 'excluded' work functions	-	577
b) implement electrified CCS	-	229
Total Potential Electric Load	**-**	**1,906**
Relative to the BASE Forecast from the 2010 Load Forecast	-	-
Net Potential New Electric Load is	**-**	**1,906**

Because these areas are still in an early stage of exploration and development, this production estimate is certainly far from certain, but prudency requires that some estimate be made. Given the amount of spending taking place in these areas, the success to date, and the similarity to the highly active Horn River and Montney Basins, the study team believes its conservative assumptions - that production will occur at one-half the rate and with a delay of eight years relative to the Horn River Basin – make adequate allowance for this uncertainty. Despite these significant discounts, the resulting projected demand of 1,900 GWh in 2025 is still a significant total, approaching 4% of BC Hydro's current electricity demand. This report asserts that the future gas production and potential electrical load of the Cordova and Liard regions should not be ignored for long-term planning purposes.

In particular, some projection of the potential for new loads in the Liard and Cordova areas should be used to solidify the justification for building the Northeast Transmission Line (NETL) to extend the BC Hydro grid into the Fort Nelson/Horn River area. Because these areas are adjacent to the HRB but further away from the transmission grid, any interconnection would rely on first extending the grid to Horn River and then extending it further to Liard and Cordova. The presence of this further future load will supplement the Horn River load as it declines, greatly extending the period over which this transmission line would serve significant load. The likelihood of an extended service period for the NETL should not be ignored in the economic justification of this transmission line.

End Notes:

[1] Map courtesy of: BC Ministry of Energy and Mines. Presentation by Christopher Adams, Oil and Gas Specialist to the BC Gas Symposium. May 31, 2011. slide 15.
[2] Ibid.
[3] Ibid, slides 18, 32, 34, 38.

2.4 Sector # 4: Liquefied Natural Gas Terminals and associated pipelines

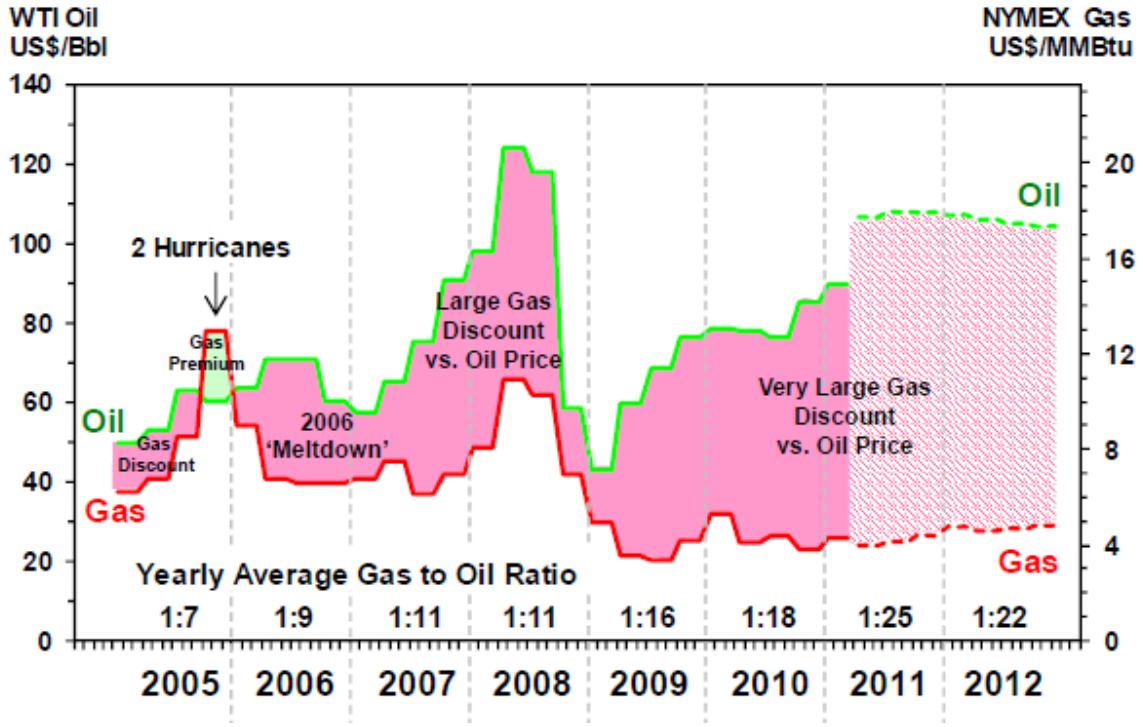
This chapter describes the Mid Case forecast of potential new electricity load required by new Liquefied Natural Gas (LNG) plants that are proposed at Kitimat and Prince Rupert.

Background: LNG refers to the liquefaction of natural gas, generally for trans-ocean transport. Gas will be transported by pipeline from the Montney and Horn River shale gas resource areas in northeast BC to ports on BC's northwest coast at Kitimat and/or Prince Rupert. On arrival at the ports, the natural gas will be compressed and chilled so that it becomes LNG, an energy-dense product suitable for shipment by marine tankers.

The economics driving this export initiative are based on the disparity between the world price of oil, at around $100 per barrel, and the North American price for natural gas, which is in the range of $4-5 per Mcf (1000 cu. ft. of gas is also approximately equal to 1 million BTUs or 1.05 gigajoules, so these terms are almost used interchangeably). On an equivalent-energy-content basis, the oil price should be no more than about six or seven times the gas price.

The chart below illustrates how the North American gas price has actually eroded over the past six years, while international oil prices have been rising. Much of this disparity has been caused by the new gas supply brought on stream as a result of shale gas development. World gas prices, in the $10-12 range, are not suffering this same discounting and so it is natural that companies will seek ways to sell North American natural gas at the world price – a price in equilibrium with the price of oil. Exporting natural gas via LNG ports to Asia is one of those ways. Converting natural gas into transportation fuels that compete with oil (described in Chapter 2.6 Alternative Transportation Fuel Plants) is another.

Figure 2.4 – 1 Relative price of natural gas and oil, 2005-2012[1]



The success of the LNG-for-export initiative will be very closely linked to the success of northeast shale gas development. The LNG plants need assured long-term supplies of gas and firm long-term contracts with growing Asian markets.

The role of electrical energy in this industrial initiative is the same for the LNG plants as it is for the shale gas developers. Electrification can neutralize the severe carbon consequences of these activities – provided the electricity itself is clean and renewable. While the large amounts of energy required for compression and refrigeration could be supplied by combusting a portion of the natural gas arriving by pipeline, it should be cheaper and cleaner to meet these needs using electricity. Accordingly, **this report anticipates that at least two of these proposed LNG plants will become major new consumers of electricity, and that the pipelines shipping the gas to these terminals are also electrified.**

Major gas producing companies with significant holdings in the northeast BC gas fields (Montney, Horn River Basin, and the Liard Basin and Cordova Embayment) are now developing the proposed LNG plants. Major international gas marketing companies are also signing long-term contracts to buy the majority of the output from the LNG plants. Developers of the most advanced LNG proposal are planning to start operations in late 2015, with plans to double the terminal's capacity by adding a second phase within two years. To date, five projects are proposed:

Table 2.4-1 – Five LNG terminals have been proposed for the north coast of BC

	Company	Location	Phase 1 Load	Start Date	Phase 2 Load	Start Date
1	**Apache, EOG, Encana**	Bish Cove, Kitimat	5 m T/yr 0.7 Bcf/d 1,500 GWh/yr	2015	10 m T/yr 1.4 bcf/d 3,000 GWh/yr	2016/7
2	**Shell, Korea Gas, China Nat'l Pet. & unnamed partners**	Prince Rupert	8.5-14 m T/yr 1.2-2.0 Bcf/d 2,500-4,200 GWh/yr	unstated		
3	**Douglas Channel LNG LP** (Haisla & LNG Partners, Houston)	Douglas Channel, Kitimat	0.9 m T/yr 0.125 Bcf/d ~300 GWh/yr	unstated		
4	**Mitsubishi, Tokyo Gas, et al. & Penn West Exploration**	Prince Rupert or Kitimat	10 m T/yr 1.4 Bcf/d 3,000 GWh/yr	late 2010s		
5	**Petronas & Progress Energy**	Prince Rupert or Kitimat	3.7 m T/yr .6 Bcf/d 1,100 GWh/yr	2017	7.4 m T/yr 1.2 Bcf/d 2,200 GWh/yr	2019

The market opportunity for LNG shipments from BC is striking. The price for natural gas in Asia is much higher than in North America, allowing natural gas producers to obtain a better price for their product.[2] BC has a distinct advantage over other areas of North America in shipping LNG to Asia, since the ports of Kitimat and Prince Rupert are significantly closer to Japan and Korea than any other LNG plants in North America, and transporting LNG by ship is more cost-effective than transport by pipeline. Colder temperatures in BC also reduce the total energy required for liquefaction, and therefore overall costs.

The particular proposals to date are as follows:

A. Apache, EOG, Encana - Kitimat LNG project:

This is the furthest advanced of all the proposals. It has already completed a National Energy Board (NEB) hearing to approve a licence to export up to 10 million tonnes per year of LNG. The partners are proposing to spend $1 billion on a pipeline,[3] plus another $2.5 billion for the first phase of the LNG plant and terminal at Kitimat (5 Mt/yr). A further $1.5 billion investment for Phase 2 will follow by 2017.

NEB approval is expected in the summer of 2011, with construction to start by the end of 2011. First shipments are scheduled for the fall of 2015.

Each phase will require about 200 MW, which at 86% load factor will require energy of about 1,500 GWh/yr. With two phases operating by 2017, the total load will be 3,000 GWh/yr.

The required energy quantities have been calculated based on a report by ABB, which describes the "shaft" energy requirements for an all-electric LNG plant producing 6.25 Mt/yr as 1,750 GWh.[4] The study team scaled this energy requirement for a 5 Mt and a 10 Mt plant and added about 200 GWh/yr for other service in the 10 Mt plant. That calculation yields 3,000 GWh/yr for every 10 Mt/yr of LNG plant production. This is the equivalent of 400 MW at an 85.6% load factor.

This proposal also includes a new 463 km pipeline along the existing Pacific Trail right-of-way, originating at Summit Lake near Station 4A on the Spectra main pipeline connecting the northeast to the Lower Mainland. The project description says there is to be only one compressor station on this pipeline. The study team estimates that electrification of this station should offer additional potential load of about 1,000 GWh/yr or more.

The project website indicates the project intends to use clean and renewable electricity to minimize any emissions.[5] This report assumes all similar projects will be required to do likewise.

B. Shell et al. - Prince Rupert LNG project.

This proposal is not as far advanced as the Apache/EOG project, but the Shell project at Prince Rupert is potentially 1.4 times the size of the Apache/EOG Kitimat proposal. (i.e. 14 million tonnes per year of LNG, requiring 560 MW or 4,200 GWh/yr). Shell has a major interest in the Montney shale gas area and is enlisting the participation of major Asian gas users such as Kogas and China National Petroleum.

If this project goes ahead, it will require another pipeline to be built because the Pacific Trail pipeline is almost at capacity with the Apache/EOG project. Accordingly it is unlikely to be on line by 2017.

C. Haisla Nation and LNG Partners LLC of Houston - Douglas Channel LNG project

This is a much smaller project, less than 20% of the size of the Apache/EOG project. The proponents are currently negotiating for space in the existing Pacific Northern Gas (PNG) pipeline and also pursuing space on the newly proposed Pacific Trail pipeline. The extract from the transcript of the NEB hearing appears to indicate that there may be sufficient space in the Pacific Trail pipeline. The project requires about 125 MMcf/day, and if additional compression is used, the capacity of the Pacific Trail pipeline could be expanded by up to 140 MMcf/day.

Since it is relatively small, this project has a reasonable likelihood of being in operation shortly after the Apache/EOG proposal. At the projected size of 40 MW, the additional annual energy load would be approximately 300 GWh/yr.[6] This project filed its application to export LNG with the NEB in July 2011.[7]

D. Mitsubishi, Tokyo Gas, Osaka Gas, Chuba Electric Power Co., and Japan Oil, Gas and Metals Corp.

This is a well-capitalized Japanese consortium that has partnered with Penn West Exploration, a gas developer with a significant interest in the Cordova Embayment shale gas play. The partners are planning to invest about $5 billion in gas extraction (400 billion yen) and another $12 billion in pipeline and liquefaction facilities ($1 trillion yen). While this level of investment should be sufficient to build a plant twice the size of the Apache/EOG plant, a recent Japanese news story reports that "the Japanese consortium and Canada's Penn West Exploration aim at producing 10 million tons of shale gas, more than 10 percent of Japan's annual imports of liquefied natural gas."[8] Accordingly, this report assumes the same 3,000 GWh/yr as required for the Apache project.

E. Petronas & Progress Energy LNG project

This project is still in the early planning stages, but Petronas, which is the world's largest LNG supplier, has announced that it needs new sources of LNG by 2013 to supply its existing customers and has acquired a 50% interest in Progress Energy's shale gas properties in the Horn River Basin area.[9] The companies have proposed that two phases will be built to process a total of 7.4 million tonnes per year of LNG. Accordingly, this report estimates the additional potential load is 2,200 GWh/yr.

Potential Electrical Load for LNG projects

If all projects were built, the total of these five proposals would give a potential export capacity of 42 million tonnes of LNG per year. That would require 6 Bcf of gas per day and, if electrified, would require about 13,000 GWh of electric energy per year**.** (3,000 GWh for every 10 million tonnes of LNG per year)

It seems very unlikely that all these projects could find the location, the assured gas supply, and the committed markets to proceed. However, this report believes that, barring a complete collapse of the Asian economies that are driving these projects, at least one project is almost certain to be built and operating by 2017, and that a second large project is also quite likely by 2020. Since the Apache/EOG/Encana project is already so far advanced, it is the most likely to proceed and be operational by our 2017 horizon. It has its location and its gas supply locked up, and expects to have sufficient contracted markets and NEB approval within a few months. It has already let contracts for site development.

The study team asserts there are six key ingredients needed to ensure that any of these projects is built:

1. The gas supply
2. The pipeline capacity to transport the gas to the coast

3. The overseas markets
4. A location for the plant that will get an environmental approval
5. Strong economic drivers
6. Political support from the community, First Nations and the province.

Furthermore, if the project is to be environmentally benign, there is a seventh key ingredient:

7. It must be powered by clean, non-emitting electricity. This may also become a factor in achieving key ingredients #4, #5, and #6 above.

The Apache/EOG/Encana project appears to have all of the first six ingredients in place, and it has a strong commitment to the seventh. All that is needed is BC Hydro's assurance that the electric energy will be available for an operating date in 2015, and an expansion in 2016 or 2017. This may require some upgrading of the transmission line from Terrace to Kitimat, and may also require some reinforcing of the line from Williston station to Terrace, but the first level of reinforcement should be quite achievable within the four- to six-year time frame.

Strong economic drivers - The economic drivers for this project are very strong and likely to remain so, barring a collapse of the world oil price, and with it the Asian price for natural gas. This will almost certainly not happen unless there is another worldwide recession that brings down the economies of China, Japan, and Korea, where most of this gas is destined.

The price differential between the North American price of around $4/Mcf (1 Mcf = 1000 cubic feet, which contains approximately 1 million Btu) and the Asian price of around $10-$12 is more than enough to cover the cost of the LNG project and the additional operating and shipping costs and still provide a healthy margin. The LNG pipeline and terminal cost around $5 billion. This requires an annual payment of around $500 million to carry the investment over 20 years (assumes an 8% weighted average cost of capital). However, the project will ship about 500 million Mcf per year.[10] This means the capital cost of the pipeline and plant is covered by $1/Mcf. Add another $2-3 for operating costs and ocean shipping and there is still a $2-3 margin on the transaction.

These economics will be sustained as long as the Asian economies continue to thrive. Accordingly, this report asserts that if the first plant is successfully built, then a second plant will follow before 2020. The other proponent groups are big enough and strong enough to secure the gas supply, the Asian markets, a second plant location, and a second pipeline route. The economic drivers and the political support will be just a strong for the second facility.

Given that the proponents of these projects are very strong companies, with access to supply and markets, and given that the economic drivers are likely to remain strong (barring another worldwide recession), it is very likely that a second project of similar size will be built and operating by 2020.

Gas Supply - Two plants would require approximately 2.8 Bcf of gas per day, but the supply from Montney and Horn River combined is projected to be more than 6.5 Bcf per day by 2020, so both plants could be supplied from these shale gas regions. Furthermore, the gas interests of the different proponents are spread around. For instance, the Apache/EOG/Encana group is primarily in the Horn River Basin, whereas Shell's interests are primarily in the Montney. The Mitsubishi/Penn West interests are focused on the Cordova Embayment. Petronas is connected with Progress Energy, which is developing properties in the Horn River Basin.

Pipeline - The location of a second facility will probably be Prince Rupert, which will require another pipeline to be built. This second facility will need another 4,400 GWh of electric energy to ensure that the project is not a large GHG emitter. This second tranche of electric energy will probably require further reinforcement of the transmission line west from Williston station (Prince George) to Prince Rupert, but there is adequate time to complete such upgrades.

Political Support – There is considerable opposition to a proposed oil pipeline and export terminal, but the situation is quite the opposite for LNG. Both the government and the opposition parties are in support of the concept of a gas pipeline and LNG export terminal.[11]

Forecast of Electricity Load

The following assumptions are made for the Mid Case estimate of electric load from LNG facilities:

1. The first plant will be operating at Kitimat by 2017, processing 1.4 Bcf/d and producing 10 million tonnes per year of LNG, and requiring 3,000 GWh of electrical energy,
2. A small Haisla project will be added at Kitimat by 2017, processing 0.125 Bcf/d and producing 0.9 million tonnes per year of LNG, and requiring 300 GWh per year of electrical energy, and
3. A second 10-million-tonne plant will be operating at Prince Rupert by 2020.

Table 2.4-2 – Mid Case Forecast of Electric Load and GHG Emissions for LNG Facilities

Estimates for new LNG facilities loads	Electric Load 2017 GWh/yr	Electric Load 2025 GWh/yr	GHGs (if not electrified) 2017 mTonnes	GHGs (if not electrified) 2025 mTonnes
First plant built and operating by 2017	3,000	3,000	1.8	1.8
Haisla project added by 2017	300	300	0.2	0.2
Second plant built and operating by 2020	-	3,000	0.0	1.8
Foundation of Potential Electric Load is	**3,300**	**6,300**	**2.0**	**3.8**
This can be further augmented by adding:				
a) compression work functions on new pipeline	656	1,259	0.41	0.78
b) incremental compression on Spectra mainline	779	1,495	0.48	0.93
Total Potential Electric Load	**4,736**	**9,054**	**2.8**	**5.4**
Relative to load provided in the 2010 Load Forecast	1,100	1,100	-0.7	-0.7
Net Potential New Electric Load is	**3,636**	**7,954**	**2.2**	**4.8**

GHG Estimation - The two columns at the right estimate the GHG emissions that are likely to occur if that particular plant or work function is <u>not</u> electrified with clean non-emitting renewable energy. This assumes that the work would be performed, instead, by the combustion of natural gas at an efficiency of 30%, which produces about 600 tonnes of CO_2e for every GWh of work energy produced.

Pipeline GHG Emissions and Work Energy – The estimates of pipeline GHG emissions were based on projections done for the Alliance Pipeline, which calculated an emission factor of 0.0448 kt $CO_2e/10^9$ m^3 km. Alliance proclaims itself to be one of the least-emitting pipelines, 21% lower than the average

for conventional systems.[12] The 0.0448 kt $CO_2e/10^9$ coefficient was used to estimate the GHG emissions for the proposed 463-km Pacific Trail Pipeline, at a throughput of 1.525 Bcf/d, and also for the incremental emissions from the same throughput passing through another 550 km of the Spectra mainline pipe. Throughputs were increased for the 2025 calculation to reflect another 1.4 Bcf/d for the second plant.

Pipeline work energy was back-calculated from the GHGs, assuming 96.5% of GHGs will come from natural gas combustion emissions at 600 tonnes per GWh (typical of compressors at 30% efficiency).

Changing circumstances have led to changing probabilities of success – The study team is not implying that these LNG facilities were unknown at the time the 2010 Load Forecast was being prepared in the fall of 2010. However, what is new since last fall is that the probability of success has risen well above 50%.

Certainly, there have been more projects proposed by reputable and credible consortiums of strong companies. But more importantly, all of the key ingredients for success are now becoming aligned. Detailed plans have been developed, hearings have been held, political support has firmed, and the economic drivers are strong.

In the fall of 2010, BC Hydro may have considered an LNG plant to be possible but not particularly probable. There were simply too many obstacles yet to be overcome. Today, the situation is much different. The likelihood of success is now in favour of at least one project and probably two being built in this decade – the gas supply is there, the markets are there, and the economics are strong.

BC Hydro's load forecast has traditionally done a good job of projecting any changes to the loads being drawn by existing customers. However, it has always been difficult and somewhat perilous to attempt to forecast structural changes that bring about totally new activities and new customers. We are at one of those junctures today, in British Columbia, where some of those structural changes could lead us to dramatically different future scenarios. This report is aimed at recognizing where those potential changes and new business opportunities will most likely be coming from.

End Notes

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[1] Ziff Energy. Presentation by Simon Mauger of the Ziff Energy group to the BC Gas Symposium. May 31, 2011.

[2] If LNG exports are perceived as becoming a significant fraction of North American production, LNG exports might affect current assumptions about a long-term natural gas "glut" in North America, raising prices even for domestic natural gas. See: Kilzer, Lou, "Natural gas prices set to jump with exports." *Pittsburgh Tribune-Review*. June 12, 2011. http://www.pittsburghlive.com/x/pittsburghtrib/news/s_741745.html . Accessed Sept 30, 2011.

[3] "Apache, EOG Buy Pacific Trail Pipeline Interest" Kitimat LNG news release. http://www.rigzone.com/news/article.asp?a_id=103927 . Accessed September 30, 2011. See also: http://www.pacifictrailpipelines.com/

[4] Devold, Håvard, Tom Nestli & John Hurter. *All Electric LNG plants: better, safer, more reliable - and profitable.* ABB Process Automation Division. 2006. Appendix A-4, pages 32-39.

[5] www.kitimatlngfacility.com/Project/project_description.aspx .

[6] Assuming a simple scaling of the ABB energy requirements noted above.

[7] "NEB to hold second LNG hearing," Calgary Herald. July 26, 2011. http://www.calgaryherald.com/business/hold+second+hearing/5158899/story.html . Accessed Sept. 30, 2011.

[8] "Natural gas imports from Canada eyed / Plan aims to cover 10% of annual total" *Yomiuri Shimbun*, July 9, 2011. http://www.yomiuri.co.jp/dy/business/T110708003661.htm . Accessed September 30, 2011.

[9] "Petronas, Progress sign C$1.07 billion deal for BC shale gas play" *Horn River News*. Weblog.

http://hornrivernews.com/2011/06/02/petronas-progress-sign-c1-07-billion-deal-for-bc-shale-gas-play/ Accessed September 30, 2011.

[10] 1.4 Bcf/day = 1.4 million Mcf/day, which is 511 million Mcf/yr

[11] For BC Liberal Party support, see: Cattaneo, Claudia."BC aims to make LNG happen," *National Post*. July 12, 2011. http://www.nationalpost.com/related/topics/aims+make+happen/5086613/story.html . Accessed Sept 30, 2011. Re: NDP support ,see: Palmer, Vaughn, "Column: NDP gives partial answer on how it will pay for programs: shipping natural gas to Asia is environmentally friendly and will promote job creation and economic growth, party's energy critic says." *Vancouver Sun*, June 14, 2011. http://www.vancouversun.com/technology/gives+partial+answer+will+programs/4940269/story.html accessed Sept 30, 2011.

[12] Alliance Pipeline Ltd. *An Action Plan for Managing Greenhouse Gas Emissions*. March, 2000

2.5 Sector # 5: New Mines

This chapter describes the Mid Case forecast of potential new electricity load required by new mines expected to be built in BC.

Background

BC's mining industry is booming. Prices for gold, silver, and copper have reached record highs. (e.g. gold over $1600/oz, silver approaching $40/oz, Copper over $4/lb) Consequently, many new mines are being actively pursued. In 2010, 380 exploration projects were active in the province.[1]

Of these 206 projects, 29 are in operation, seven are closed, twenty are classified as in advanced exploration, and fourteen are in the most advanced stage of permitting or environmental assessment.[2]

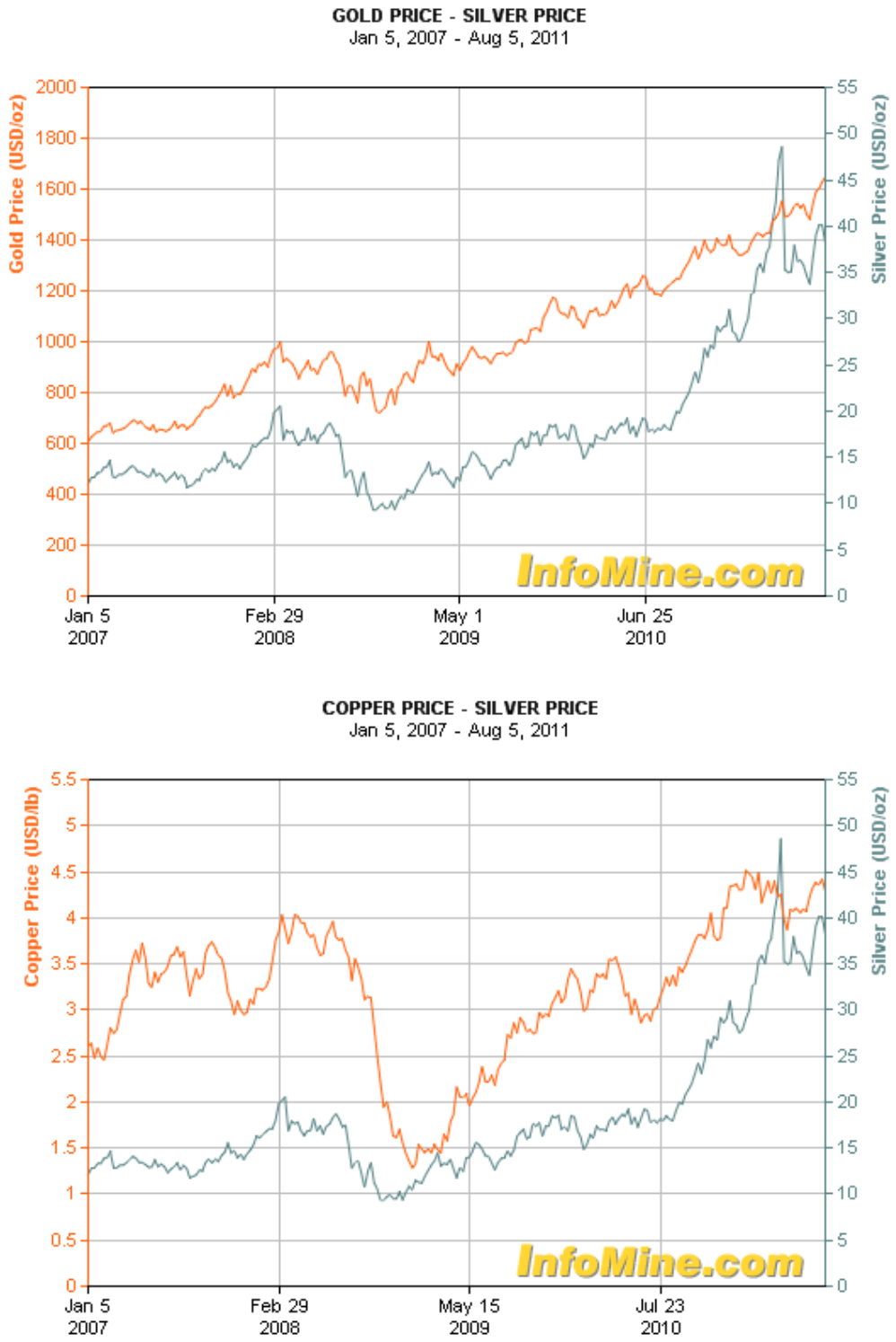
This report focuses on the fourteen most advanced projects as the representative sample that is most likely to come into production within the next five to six years. Of these, ten are in the northwest section of B.C, and reasonably close to BC Hydro's new proposed Northwest Transmission Line or the northern extension of that line. All of the other projects are within 100 km of an existing grid connection.

If these fourteen projects have access to electricity from the grid rather than using diesel generation, the study team estimates that they could require a new potential load of 7,000 GWh/yr or more.

Note that this analysis focuses only on the potential new load from the commercial operation of new mines, rather than additional demand resulting from the expansion of existing mines. The study team assumes that existing mines that are expanding their production are already included in BC Hydro's December 2010 Load Forecast.

The economics for most of these new mines will be driven by gold, silver and copper prices, which have all made significant recoveries since the 2008 recession, as shown in the following charts:

Figure 2.5-1 – Five year history of selected metal prices[3]



The table below lists the 14 projects in the most advanced stage of permitting or environmental Assessment (EA), and also shows their expected production rates and the potential electrical load from each project.

Table 2.5-1: 14 Most Advanced Potential New Mines

ELECTRICAL LOAD POTENTIAL - 14 Most Advanced New Mine Developments in B.C.

Project	Owner	Mine Type	Minerals	Status	Ore Output	Estimated COD	Power & Energy Needs		Nearest Connectio	Distance
					tpd		Mid Est. MW	Mid Est. GWh	substation / line	km
Bear River Grave	Glacier Aggregate Inc.	Open Pit		Permitting or EA	2,750 tpd	n year 3-4 of the project (Guess 2016	5 MW	23 GWh	STW	
Kitsault	Avanti Mining Inc.	Open Pit	Mo,Ag,Pb	Permitting or EA	40,000 tpd	End of 2013	70 MW	337 GWh	AIY	42
Schaft Creek	Copper Fox Metals Inc.	Open Pit	Cu,Au,Ag,Mo	Permitting or EA	120,000 tpd	Feasibility TBC by end 2011	210 MW	1,012 GWh	BQN	81
KSM	Seabridge Gold Inc.	Open Pit	Au,Cu,Ag,Mo	Permitting or EA	120,000 tpd	>2015 (Powerline connection date)	210 MW	1,012 GWh	BQN	20
Galore Creek	Teck/Novagold	Open Pit	Cu,Au	Permitting or EA	95,000 tpd	PFS end of July 2011 (Guess 2016)	166 MW	801 GWh	BQN	70
				NWTL connect	377,750 tpd	all before 2017	661 MW	3,185 GWh		
Ruby Creek	Adanac Moly Corp.	Open Pit	Mo	Permitting or EA	23,000 tpd	Construction to take ~2yrs	40 MW	194 GWh	Atlin	
Kutcho Creek	Captone Mining Corp.	Open Pit	Cu,Zn,Au,Ag	Permitting or EA	4,000 tpd	Yr 3 of project (underground in yr 1)	7 MW	34 GWh	BQN-north	220
Mt. Klappan	Fortune Minerals Ltd.	Open Pit	anth. coal	Permitting or EA	8,000 tpd	Positive Feasibility Study (Guess 2015	14 MW	67 GWh	BQN-north	100
Turnagain	Hard Creek Nickel Corp.	Open Pit	Ni,Co,Pt	Permitting or EA	87,000 tpd	>2013 (Powerline connection date)	152 MW	734 GWh	BQN-north	190
Red Chris	Imperial Metals Inc.	Open Pit	Cu,Au	Permitting or EA	50,000 tpd	Positive PFS (Guess 2015)	88 MW	422 GWh	BQN-north	120
				N of NWTL	172,000 tpd	all before 2017	301 MW	1,450 GWh		
Raven	Comox Joint Venture	Feasibility	coal	Permitting or EA	3,000 tpd	Late 2013	5 MW	25 GWh	1L119	5
McNab Valley	BURNCO Rock Products	Open pit - sand/gravel	aggregate	Permitting or EA		Septmeber 2013	0 MW	0 GWh	1L31	1
Blackdome	Sona Resources Corp.		Au,Ag	Permitting or EA	200 tpd	2013	0 MW	2 GWh	2L86	35
Mt Milligan	Thompson Creek		Au,Cu,Mo,Re	Permitting or EA	60,000 tpd	First quarter of 2013	105 MW	506 GWh	KDY	86
				Rest of BC	63,200 tpd	all before 2017	111 MW	533 GWh		
				GRAND TOTAL	612,950 tpd	all before 2017	1,073 MW	5,168 GWh		

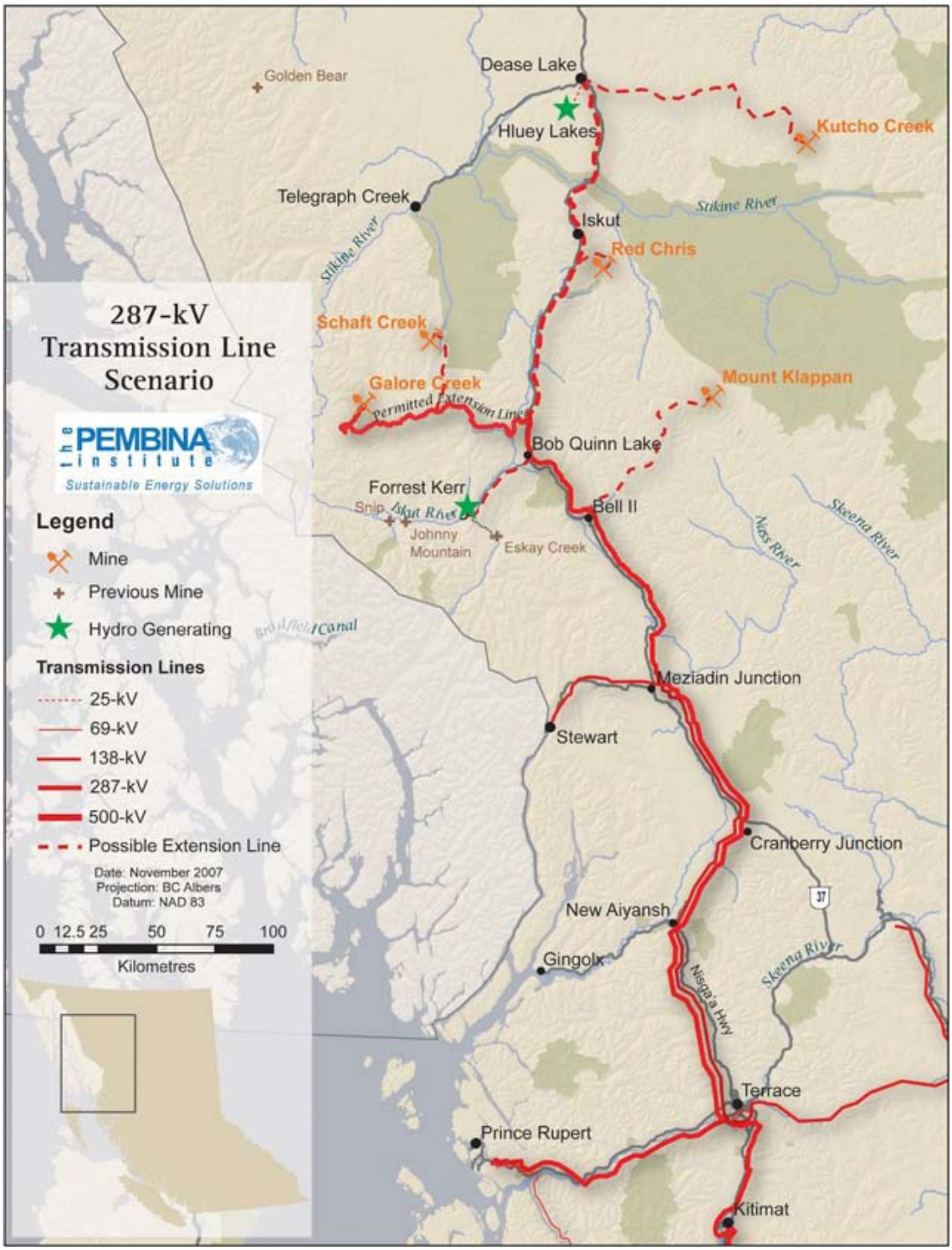
The potential new electrical load from these projects has been estimated by our engineering consultants, based on their general experience, to be in the range of 1.5 to 2 MW per thousand tonnes per day (ktpd) of ore production. The table above assumes a mid-point value of 1.75 MW per ktpd and a 55% load factor to calculate the annual energy requirement. At a 55% load factor, these projects could require a potential annual energy of 4,000 to 6,000 GWh/yr, with a mid-level estimate of 5,000 GWh.

The consultants have also estimated the likely commercial operation dates for each project. Notably**, all of these mines have commercial operation dates (CODs) projected to occur before 2017**.

These are the most advanced projects in the province, but there are twenty additional projects that are close behind them, in the advanced exploration stage. Should any of these fourteen most advanced projects fail to proceed, it is assumed that some of these twenty other advanced projects will soon take their place.[4] This assumption is, of course, based on a continuation of the mineral prices that are driving these projects. It is possible that this price trend could change dramatically if, for instance, another global recession were to ensue within the next two years. However, such an event is not considered likely enough to be used as the foundation for long-term planning.

The map below shows the location of several of the projects along the new NWTL route and its potential extension to Iskut and Dease Lake.

Figure 2.5-2 – Map of Northwest Transmission line (NWTL) and possible extension to Dease Lake[5]



Of the potential new load, 90% (approximately 960 MW or 4,600 GWh/yr) is located within a reasonable connecting distance of the new 287 kV NWTL or the extension of that line to the North. (The possible extension to Iskut and Dease Lake has been rumored, but not yet officially announced by BC Hydro).

Of the remaining four projects, only Mt. Milligan is significant, and the developers of this project have already done a feasibility study for a new 230 kV line to connect to BC Hydro's Kennedy substation north of Prince George.[6]

In summary, the planned new mines connecting to the NWTL could potentially add an additional 962 MW or 4,600 GWh/yr, which can be divided into two classes depending on their location relative to the new NWTL:

i. From Terrace to Bob Quinn (NWTL South) – 661 MW or 3,185 GWh/yr.

ii. North of Bob Quinn (NWTL North) – 301 MW or 1,450 GWh/yr.

The map below shows the location of numerous other potential new mines in the northwest region.

Figure 2.5-3 – Operating Mines and Selected Major Exploration Projects in Northwest BC[7]

Of the four most advanced new mines located in the rest of BC, only the proposed Mt. Milligan mine can be expected to require significant new electrical loads (105 MW, with an load of 506 GWh/year).

Assumed timing of new potential mining loads

All of the fourteen mining projects noted above have projected CODs (Commercial Operation Dates) before 2017.

However, the study team makes the conservative assumption that of the five advanced projects that can be readily connected to the NWTL, only three will be in place and operating by 2017. The study team chose to use estimates of energy demand for three specific mines, rather than try to generate an average per-mine demand factor (the reader should note that the choice of these particular mines is arbitrary, and is not intended to reflect the relative likelihood of these specific projects being implemented).[8] These three projects would result in a combined new load of approximately 600 MW and 2,800 GWh/yr by 2017.

The study team also assumes that only two of five additional projects that are also located in the northwest but would require an extension of the NWTL will be in place and grid connected by 2020.[9] The study team estimates that these two additional projects will increase the total connected new load to 800 MW and 4,000 GWh/yr by 2020.

The study team also assumed that one other new project would be grid-connected at Kennedy substation north of Prince George by 2017.[10]

Likelihood of new potential mining load

The list of active projects in BC starts with more than 200 candidates and, of these, 14 projects are in the most advanced of permitting and environmental approval. Of these 14, we have selected six that have easy connectivity to the electric grid. (These six projects are highlighted in Table 2.5-1).

These six projects represent a realistic, but conservative, expectation for the new load potential in the next six to eight years. Even if some of these six projects are delayed, there are another eight mines on the list of 14, plus another 20 projects in the stage of advanced exploration that will be ready to take their place if commodities markets remain at today's levels.

Therefore, these six projects constitute a very reasonable mid-level estimate of the new load potential within the 2017-2025 time horizon. **To reiterate, this new energy load is likely to occur, in one form or another.** Assumptions about how much of it is electrified versus how much will be provided by fossil-fuel energy is addressed in Chapter 4: "Electrification and Supplemental Load Forecast."

Forecast of New Electricity Load

To recap, the mid-level estimate for new mining electricity load assumes that:

1. Three new mines easily connectible to the NWTL will be operating and grid-connected by 2017.
2. Two new mines needing an extension of the NWTL will be operating and grid-connected by 2025,
3. One additional mine in north-central BC is also assumed to be operating and grid-connected by 2017.

Table 2.5-2 – Potential load for new mines

Estimates for New Mine Developments	2017 GWh/yr	2025 GWh/yr
3 mines along NWTL	2,825	2,825
1 mine connecting in north-central BC	506	506
2 mines connecting to extension of NWTL		1,155
Foundation of Potential New Electric Load is	**3,330**	**4,486**
Total Potential Electric Load	**3,330**	**4,486**
Relative to the BASE Forecast from the 2010 Load Forecast	1,900	1,900
Net Potential New Electric Load is	**1,430**	**2,586**

Expansion of Existing Mines

This report makes the assumption that the expansion (and contraction) of BC Hydro's existing mining customer loads is already being forecast within BC Hydro's December 2010 Load Forecast. Therefore, this report focuses only on potential new mines.

BC Hydro's 2010 Load Forecast states that "sales are on average about 1,000 GWh higher… between F2014 to F2030. Much of this increase is due to improved expectations for mining operations."[11] We have drawn the inference that this 1,000 GWh increase is the provision for the growth of existing mining operations and that, therefore, the 1,900 GWh balance of the increase in the Load Forecast with respect to mining is a provision for new mines (see discussion in Chapter 3 below).

Since the 2010 Load Forecast was prepared in the fall of 2010, there have been many announcements of the expansion of existing mines. With these subsequent announcements, it is possible that there are now more expansions than were included in the 1,000 GWh provided in the 2010 Load Forecast but these are not included in this report.

Absence of data on additional work energy or GHG emissions

It is certain that a considerable amount of additional energy will be used, probably in the form of diesel fuel for hauling trucks, diggers, or other mobile equipment. However, the study team was not able to locate data on the additional work energy required by mines similar to those included in the mid-level estimate. This data would be essential for making any educated estimate of the GHG emissions that should be expected from these new mines and/or for making any estimate of the potential for further electrification of mining. In the absence of more detailed information, the study team applied an electrification factor closely following the historic relationship observed by BC Hydro (approximately 23 MWh per 1000 tonnes of ore milled).[12] However, the study team concludes that there may be many opportunities for additional electrification, such as using electric conveyer systems or electric vehicles for certain types of hauling.

Recommendations for mining electrification

New mines will almost certainly be contributors to provincial and global GHG emissions but, in the absence of reliable data on total work energy or GHG emissions, it is difficult to know what possibilities might exist for greater electrification of the mining industry. We therefore recommend several courses of action.

1. The Ministry of Energy and Mines should **undertake a definitive study into the GHG emissions of the mining industry** and the opportunities for further electrification.
2. The mining industry should be **either required to electrify**, by codes and standards, **or incented to electrify**, by increasing the cost of carbon emissions, as much work energy as possible in order to minimize the GHG emissions of the industry.

End Notes:

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[1] BC Ministry of Energy and Mines, "$12 million in funding to explore BC's potential" News Release. May 10, 2011.

[2] One additional large project, Prosperity, was refused but is currently resubmitting.

[3] http://www.infomine.com/

[4] Taseko's proposed Prosperity mine is not included in this list of fourteen projects. If resubmitted and accepted, this mine could add a further 700 GWh/yr of energy demand.

[5] Pembina Institute. *Sizing it Up*. February 2008.

[6] *Mt. Milligan-230kV Transmission Line Feasibility Study Preliminary Report*. Version 2.0 Prepared by Wardrop Engineering Inc. for Terrane Metals Corp. 2008.

[7] Map courtesy of BC Ministry of Forests, Lands and Natural Resource Operations.

[8] The mines selected for the purpose of this load estimation exercise are Galore Creek, Schaft Creek, and KSM. The study team notes that the choice of these mines is arbitrary, and does not indicate the relative likelihood of these projects proceeding relative to other projects.

[9] The mines selected for the purpose of this load estimation exercise are Red Chris and Turnagain. The study team notes that the choice of these mines is arbitrary, and does not indicate the relative likelihood of these projects proceeding relative to other projects.

[10] Mt. Milligan. The study team notes that the choice of this mine for load estimation purposes is arbitrary, and does not indicate the relative likelihood of this project proceeding relative to other projects.

[11] BC Hydro. *2010 load forecast*. p. 47.

[12] BC Hydro's 2007 Conservation Potential Review, Industrial Sector, found the Electric Energy-use Intensity for metal mines was 23 kWh/tonne of ore milled, which is 23 MWh per 1000 tonnes of ore. This report uses a similar value by calculating 1.75 MW/ktpd at a 55% load factor, which is 23 MWh per day per 1000 tonnes.

2.6 Sector # 6: Alternative Transportation Fuel Plants

Background

This sector involves new industrial-scale facilities that produce transportation fuels using alternatives to petroleum oil. There are now two proposals for large-scale production of alternative transportation fuels in BC: Blue Fuel Energy (methanol and /or synthetic gasoline) and Sasol GTL (gas-to-liquids technology).

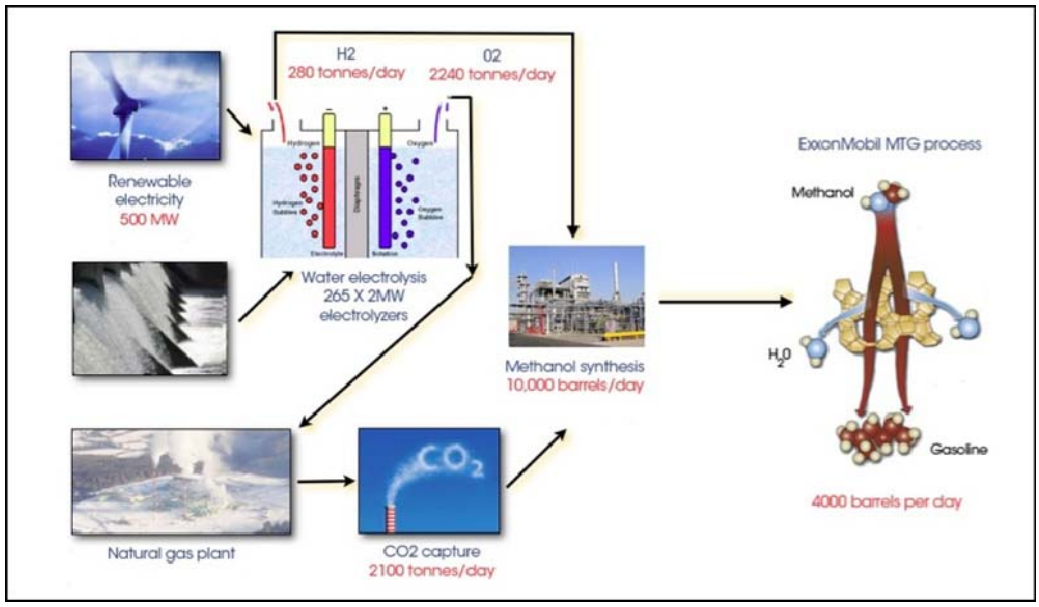
As discussed in Chapter 2.4, the economic forces driving the production of alternative fuels are similar to those driving the movement towards LNG for export:

- The high value difference between the world price for oil-derived fuels and the low prices for North American natural gas,
- The projected increase in the cost of carbon emissions.
- Increased interest by the US government in reducing the US dependence on crude oil from strategically vulnerable regions.

1. **Blue Fuel -** A multi-billion dollar Blue Fuel plant has been proposed near Chetwynd, BC. The plant would use the CO_2 derived from the processing of natural gas as a feedstock to make various fuels that are used in transportation vehicles. See the BlueFuel website for a description of the process and its GHG emission benefits.[1]

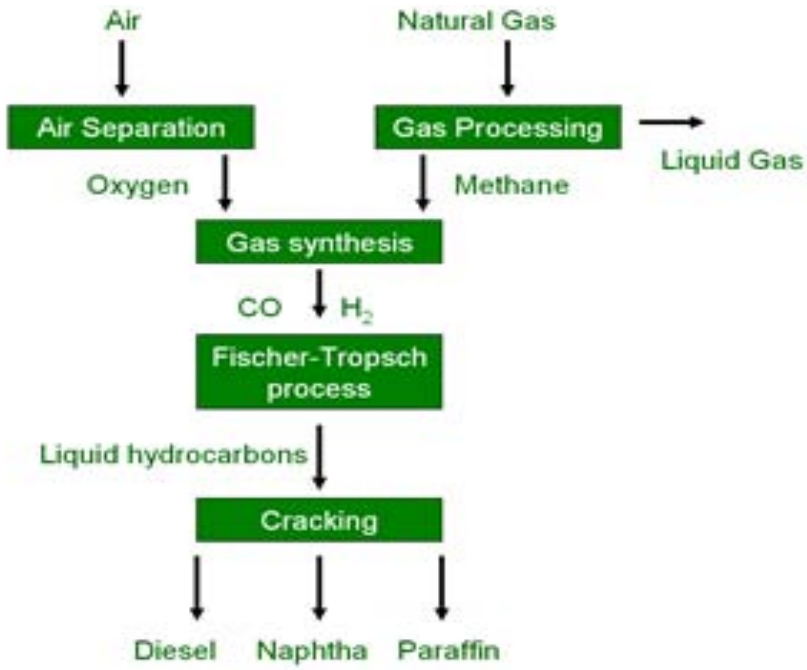
   The proponent states that the plant will require approximately 4,200 GWh/yr in full operation and has already submitted a power supply request to BC Hydro for this amount.

   Figure 2.6-1 – The Blue Fuel process



2. **Sasol GTL –** Sasol, a South African company with a long history of producing liquid fuels from coal using the proven Fischer-Tropsch process, has announced interest in another multi-billion dollar plant near BC's new shale gas fields. The proposed SasolFuel plant will process natural gas into liquid fuels.

Figure 2.6-2 – The SasolFuel process[2]



Sasol and Talisman Energy recently signed an agreement to investigate the feasibility of, and to potentially build, a plant able to convert shale gas to GTL naphtha (GTL=gas-to-liquids), diesel and liquefied petroleum gas using Sasol's proprietary technology.[3]

The size of the potential plant, and the energy requirement for the Sasol technology, are yet to be announced and there are insufficient technical details released to allow a reasonable estimate at this time.

Forecast of New Electricity Load

The economic drivers appear strong for either or both proposals: the high price of oil-derived fuels; the low price of natural gas; and the increasing cost of carbon emissions.

With the Sasol load as yet undetermined, this report makes the conservative assumption that, for the Mid Case scenario, only one of these two plants will proceed and the total potential load for this category will be equivalent to the Blue Fuel facility's projected load of 4,200 GWh/yr. It further assumes that that it will take up to 14 years, or 2025, for the plant to reach COD.

Table 2.6-1 – Potential electric loads from Alternative Fuels

Estimates for Alternative Fuels Developments	2017 GWh/yr	2025 GWh/yr
One or the other of BlueFuel or Sasol will proceed		4,200
Foundation of Potential New Electric Load is	**-**	**4,200**
Total Potential Electric Load	**-**	**4,200**
Relative to the BASE Forecast from the 2010 Load Forecast	-	-
Net Potential New Electric Load is	**-**	**4,200**

2.7 Summary of Six Sectors Potential Work Energy

The Mid Case forecast for Potential Electrifiable Work Energy for the six sectors is as follows:

Table 2.7-1 Potential Electrifiable Work Energy (GWh)

Sector:	***2017***	***2025***
Montney Basin natural gas activities	4,083	4,742
Horn River Basin natural gas activities;	3,812	5,771
Liard/Cordova Embayment Basin natural gas activities;	0	1,906
New Liquefied Natural Gas terminals and pipelines;	4,736	9,054
New mines; and	3,330	4,486
New plants to produce alternative transportation fuels	0	4,200
Total	**15,961**	**30,158**

The forecast of approximately 30,100 GWh of Potential New Work Energy by 2025 and 15,900 GWh by 2017 is for all of the identified energy required by project activities. This total should not be confused with the net additional load – it is first necessary to determine what percentage of this load can be successfully electrified, and how much of this energy demand is already included within BC Hydro's 2010 load forecast.

But not all of it can be electrified. Some demand for energy will be situated too far from the grid, even after transmission extensions, while other energy use will be too spread out to justify extending wires everywhere. Energy use at some sites will be required before wires can be extended to service them. Finally, projects that also require heat may find co-generation cheaper even if natural gas and diesel prices rise considerably over time.

To adjust for the practical limits of electrification, each sector's Potential Electrifiable Work Energy is discounted for a reasonable degree of electrification to determine the Potential Electricity Load. These electrification assumptions and calculations are described in Chapter 4.

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[1] "Blue Fuel Energy will use renewable electricity to electrolyze water, and then catalytically react the hydrogen isolated through this process with waste carbon dioxide (captured from natural gas processing plants) to produce ultra-low-carbon methanol and gasoline." http://www.bluefuelenergy.com/blue-fuel-methanol-production/blue-fuel-methanol-production.html Accessed Sept 30, 2011.

[2] www.sasol.com

[3] "Sasol agrees $1bn Talisman Energy gas field deal." *BBC News - Business*. Website. http://www.bbc.co.uk/news/business-12037184 . Accessed September 30, 2011.

Chapter 3: BC Hydro 2010 Industrial Load Forecast, Interpretation and Comparison

3.1 BC Hydro 2010 Electric Load Forecast - 2010/11 to 2030/31

In December 2010, BC Hydro produced the most recent iteration of its annual 20-Year Load Forecast[1]. As this particular load forecast was used as the basis for development of the Integrated Resource Plan (IRP) in the first months of 2011, it has had a significant influence in shaping current perceptions about what actions are required to meet new customer demand.

BC Hydro itself drew the following conclusions from its 2010 load forecast:

- Electricity demand is growing in British Columbia, with the 2010 load forecast showing over 40% growth in demand over the next 20 years.
- One of the key drivers is the anticipated growth and potential load in the oil and gas sector in BC's northeast and the mining sector in the northwest.
- This demand has a higher risk profile than changes in load growth that are driven by broad trends such as population growth or consumption behaviour.
- The conditions that create the industrial load growth potential in the resource extraction sectors above can change quickly. Examples of these conditions are commodity prices, interest rates, technology and product demand.
- The risk is further concentrated in a relatively small number of customers.
- BC Hydro sees the potential for significant growth in these sectors due to favourable metal prices and transformative technologies in shale gas production.
- Prior to submitting the 2011 IRP, BC Hydro will re-evaluate the load forecast and make adjustments as needed.

3.2 General Approach and Methodology

This report utilizes a significant amount of information contained in the BC Hydro December 2010 Electric Load Forecast - 2010/11 to 2030/31 ("2010 Load Forecast") including:

- Industrial Sales (GWh) for relevant sectors or regions.
- Industrial Sales before demand side management and rate impact were utilized, wherever they were specified.

This report focuses on energy (GWh) and not capacity (MW).

Where loads were forecast in MW, the study team estimated appropriate load factors for the sectors in question to convert MW to GWh. For instance, BC Hydro's June forecast of 700 MW for Horn River Basin peak annual load (for the high scenario) in 2025 was converted to 4,906 GWh based on an assessment by the study team that the average load factor for these activities would be 80%.

The specific load factors used by the study team for each of the six major load categories and subcategories (i.e. plants vs. pipelines), is described in the next section.

Each load category utilized different numbers and statements from the BC Hydro 2010 Load Forecast as described in the six separate sections below.

3.3 Interpretation of BC Hydro 2010 Load Forecast for the Six Major Sectors

The study team drew certain conclusions from BC Hydro's December 2010 Load Forecast with regard to the load amounts included in the reference forecast for each of the six sectors.

The study team also utilized information in that document to build its new forecast of the potential new loads for those six sectors.

Sector #1: Montney Basin natural gas activities

The study team judged that the 2010 load forecast for Montney Basin gas activities showed amounts of 1,939 GWh in 2017 and 2,359 GWh in 2025. These numbers were derived from data presented in Table A3.1 "2010 and 2009 Gas Load Forecasts Before DSM and Rate Impacts (GWh) and Production Forecasts."

This study team assumed that the load area for the "Integrated Area (Peace region)" is equivalent to the load area for the Montney Basin gas activities.

Sector #2: Horn River Basin natural gas activities

The study team judged that the 2010 load forecast for Horn River Basin gas activities showed amounts of 892 GWh in 2017 and 1,092 GWh in 2025. These numbers were derived from data presented in Table A3.1 "2010 and 2009 Gas Load Forecasts Before DSM and Rate Impacts (GWh) and Production Forecasts."

The study team assumed that the load area for the "Non-Integrated Area (Fort Nelson)" is equivalent to the load area for the Horn River Basin gas activities.

Sector #3: Liard Basin/Cordova Embayment natural gas activities

The study team judged that the 2010 load forecast for the Liard Basin/Cordova Embayment gas activities showed amounts of 0 GWh in 2017 and 0 GWh in 2025.

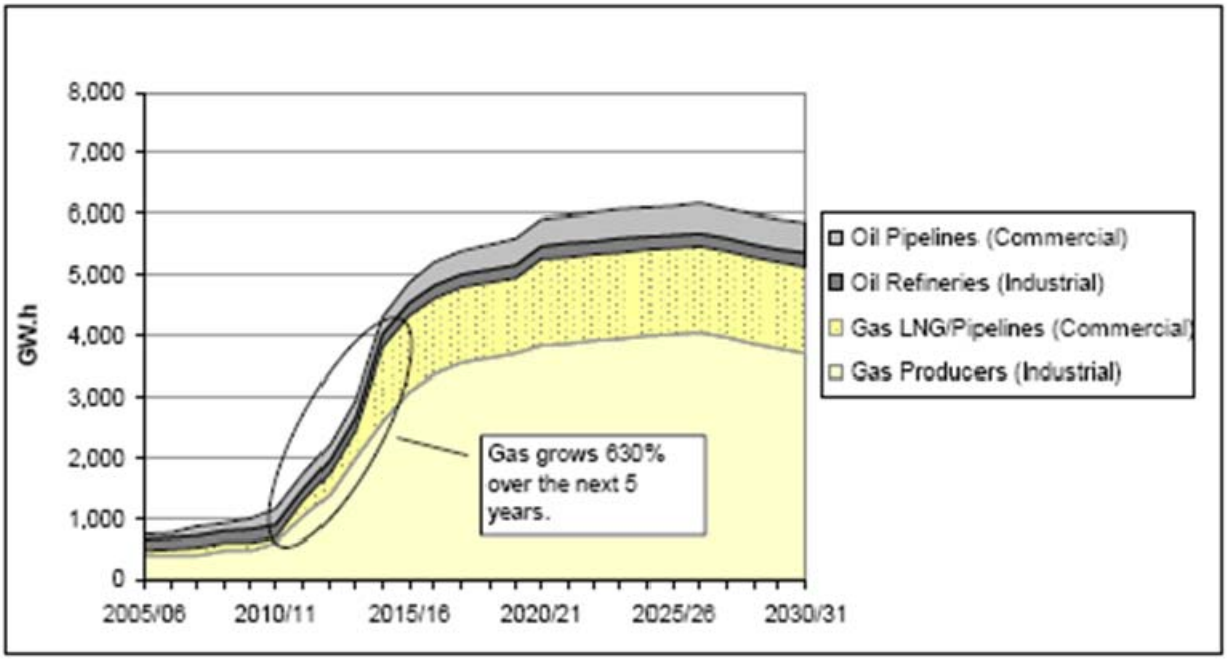
No information was available to be gathered from the 2010 Load Forecast to analyze and forecast new potential load growth in the Liard Basin/Cordova Embayment area.

Similarly there are no electricity load numbers or gas production numbers for the Liard Basin/Cordova Embayment basins in the 2010 Load Forecast.

Sector #4: New liquefied natural gas plants (LNG)

The 2010 Load Forecast appears to include a modest provision for the growth of liquefaction operations as shown below in Figure A3.1, taken from Appendix 3.1 of that document.

Figure 3-1 – BC Hydro's 2010 forecast for the Oil & Gas Sector



The 2010 Load Forecast states: "When compared with the 2009 Forecast, the 2010 Forecast is about 1,100 GWh higher due to heightened expectations for liquefaction operations."[2]

In addition, the study team observed that the band titled "Gas LNG/Pipelines (Commercial)" in Figure A3.1, appears to grow by about 1,100 GWh by the year 2015/16 and thereafter. The study team therefore inferred that the 2010 Load Forecast contains a load growth of about 1,100 GWh/yr with respect to new LNG plants.

Sector #5: New Mines

Table 8.1 of the 2010 Load Forecast shows the load attributed to metal mines increasing from 2,291 GWh in 2011 to 5,177 GWh in 2018 before dropping off due to the closure of Highland Valley Copper.

The text of the load forecast states: "…sales are on average about 1,000 GWh higher … between F2014 to F2030. Much of this increase is due to improved expectations for mining operations."[3] However, it is unclear how much of the total increase of 2,900 GWh is due to "improved expectations" for existing operations and how much is due to new mines coming into operation.

The study team has therefore drawn the inference that approximately 1,000 GWh of the load increase is due to the growth of existing operations, and the balance of approximately 1,900 GWh is a provision for new mines coming into operation, without identifying those mines specifically.

Since the purpose of this report is to focus on the potential new load that might arise from new mines, rather than the growth of existing operations, only the 1,900 GWh amount is relevant to the new mines sector examined in this report.

Sector #6: New plants to produce alternative transportation fuels

The study team saw no indication within the 2010 Load Forecast of any provision for new industrial plants coming into operation to produce alternative transportation fuels. The study team understands that BC Hydro is not in the practice of adding such new customers to its load forecast until relatively firm contracts for service are signed.

The study team therefore concluded that there is zero provision in the 2010 Load Forecast for any such new projects and that any such new potential load should be treated as being incremental to the 2010 Load Forecast.

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[1] BC Hydro. *2010 load forecast*. 2010. 141pp. Chapter 8 addresses the industrial load forecast for areas serviced by BC Hydro's main transmission system. Industrial loads outside of that system are addressed in Chapter 9.1, Non-Integrated Area Summary. Appendix 3.1 focuses on the Oil and Gas Sector, and Appendix 3.2 focuses on Gas Producers in the Northeast Gas region.

2 ibid. p.89

[3] Ibid. p.47

Chapter 4: Electrification and Supplemental Load Forecast

This chapter converts the Potential Work Energy Forecast (determined in Chapter 2) to Potential Electricity Load by multiplying the Work Energy for a sector by the "Degree of Electrification" determined for that sector.

4.1 Degrees of Electrification

The discount factors used for the degree of electrification in each load category impose a further measure of conservatism on the amount of electrical load that may be realized in each case. Each sector has a different degree of potential electrification.

Single new plants, like the BlueFuel or Sasol plant, have full potential to be electrified. Full electrification is also possible for LNG terminals, but electrifying related pipeline activities that are spread out and may have some portions already operating is more difficult. Some new mines may be too far from the grid, or have a mineral processing step that requires heat (and hence favours co-generation). Alternatively, mine sites may develop an off-grid, small hydroelectric site nearby – all of which lowers the proportion of new mines that are likely to be electrified.

Northeast gas basin activities are quite spread out, with some being very remote. Some functions are not well suited to electrification. Existing operations may already own their fossil-fuelled drills and compressors. Electrifying small drill rigs may be impractical, especially if their local gas field has a short production life. Each sector's allowance for the degree of electrification is specified and explained below.

Table 4-1 - Potential New Work Energy discounted for degree of project electrification (GWh)

Sector	Major Potential Work Energy Identified		% Allowance for Degree of Project Electrification		Major Potential Load After Allowance For Electrification	
	2017	2025	2017	2025	2017	2025
Montney Basin O&G	4,083	4,742	73%	73%	2,997	3,483
Horn River Basin O&G	3,812	5,771	70%	70%	2,659	4,027
Cordova/Liard O&G	-	1,906		70%	-	1,334
LNG Terminals & Pipelines	4,736	9,054	84%	83%	3,956	7,559
New Mines	3,330	4,486	70%	70%	2,331	3,140
Alternative Fuel Plants	-	4,200	100%	100%	-	4,200
	15,961	30,158	75%	79%	11,943	23,743

1. **Montney** - The **73%** factor, in effect, removes any of the augmentations that were considered achievable in Table 2.1-4, including additional work functions, higher intensity, higher service percentage, and carbon capture and sequestration. It drops the electrical load back to the level of the basic 0.115 intensity on the 'included' work only. This level of electrification

basically assumes that the wide dispersion of the many work sites in the area makes it impractical to achieve the higher electrification potential.

2. **Horn River** – The **70%** factor, in effect, assumes that the 20% augmentation of work functions cannot be achieved but assumes the requirement to electrify carbon capture and sequestration will continue.
3. **Cordova/Liard** – The **70%** is simply to emulate the Horn River degree of electrification, based on the similarity of the two regions.
4. **LNG Terminals and Pipelines** –The **84%** factor, in effect assumes that the large centralized processing plants at the LNG terminals will be fully electrified and the new dedicated pipelines will also be fully electrified. However, it assumes that the Spectra mainline will not be retrofitted to electrify the incremental shipments.
5. **Mines** –The **70%** factor is simply a further element of conservatism, to in effect represent the attrition of two of the six mines, thus reducing the total number of new mines proceeding from six to four, without speculating as to which specific mines will not proceed.
6. **Alternative Fuel Plants** – The **100%** factor is used because these are compact and centralized processing plants, each in a single location. They will be located near to the electric grid, making them easy to fully electrify.

This report essentially assumes that where a work function can be electrified or a transmission line could be constructed to serve the load, then within reason, this is done and done promptly.

Despite this assumption, the study team acknowledges that the aggressive electrification assumed here will often be challenging to achieve in practice. BC Hydro, as the implementer of electricity policies, has the responsibility for rules and rates and, as the builder of transmission lines, has the challenging task of evaluating the cost and the economic justification for these lines. Additionally, it must co-ordinate those actions with the BC-wide work schedules that are already in progress.

It should be noted that the study team was not privy to information that BC Hydro may have on additional physical or economic constraints that may temper the higher levels of electrification intensity and service percentages, as well as the timing of transmission extensions, that have been assumed in the report.

However, it should also be noted that if the assumed levels of electrification are not achieved, then the required work energy will likely be supplied by burning fossil fuels instead, resulting in emissions of air pollutants and greenhouse gases.

4.2 Supplemental Load Potential

Comparing the Potential Electrical Loads to the amounts included in BC Hydro's 2010 Load Forecast determines the "Supplemental Electric Load Potential." The supplemental loads are shown in the following table.

Table 4-2 – Comparison of forecast electrified loads to BC Hydro 2010 Load Forecast (GWh)

Sector	Major Potential Load After Allowance For Electrification		Amount Included in Dec. 2010 Load Forecast		Supplemental Electric Load Potential Identified	
	2017	2025	2017	2025	2017	2025
Montney Basin O&G	2,997	3,483	1,939	2,359	1,058	1,124
Horn River Basin O&G	2,659	4,027	892	1,092	1,767	2,935
Cordova/Liard O&G	-	1,334	-	-	-	1,334
LNG Terminals & Pipelines	3,956	7,559	1,100	1,100	2,856	6,459
New Mines	2,331	3,140	1,900	1,900	431	1,240
Alternative Fuel Plants	-	4,200	-	-	-	4,200
	11,943	23,743	5,831	6,451	6,112	17,292

The results in Table 4-2 show a total “supplemental” load potential for 2017 of approximately 6,100 GWh and 17,300 GWh for 2025. This is the amount of the heavily discounted potential load that is incremental to load already included in BC Hydro’s 2010 Load Forecast.

Chapter 5: High Case Forecast

The Mid Case forecast in Chapter 2 assumes that most of the new mines, terminals and plants that have been announced will not proceed, and that the strong gas production projections made will not be realized to their full extent. It heavily discounts these announcements to account for the significant challenges of developing industrial projects, and the high volatility of mineral and gas prices. This chapter shows the sensitivity of electricity load forecast amounts to the level of discounting, by presenting a High Case forecast based on a more modest level of discounting. The assumptions and results of each case are shown below.

5.1 Review of Mid Case Forecast Assumptions and Results Summary

For activities in the Montney Shale Gas Basin, the Mid Case forecast uses CAPP's gas production forecast, which is 19% lower than BC Hydro's 2025 High Forecast and 43% below the customer requests they have already received.

For the Horn River Basin, the Mid Case gas production forecast is an average of two gas industry forecasts, which is 46% lower than BC Hydro's 2025 High Forecast.

For the Liard Basin and Cordova Embayment gas fields, even though these basins have a larger area than Horn River, this report assumes a gas production forecast that is only 50% of the Horn River levels, and defers production by eight years, even though the current pace of land rights acquisition indicates that the Liard and Cordova regions are only about three to four years behind Horn River.

For LNG, the report assumes that only one of the four large LNG terminals that have been announced will be built by 2017. One of them expects to receive its National Energy Board permit within a month and aims to start construction before the end of this year. A much smaller LNG terminal, co-led by a local First Nation, has also applied for its LNG permit and is also forecast to be built by 2017. For 2025, the report assumes only one of the other three announced LNG projects will be built.

For new mines, the report assumes that, of the 206 projects that are at various stages of development, only four will be built by 2017 and only two more built by 2025. This is fewer than half of the most advanced 14 new mines that are already at the final stages of permitting or environmental assessment.

Two companies have announced plans to build multi-billion dollar plants that would produce transportation fuels using alternatives to petroleum oil. Despite the strong business case of record spreads between oil and natural gas prices, the projected increase in the cost of carbon emissions, and governmental desire to reduce dependence on oil imports, the Mid Case assumes only one of these two plants will be built and gives it 14 years, until 2025, to be built.

The Mid Case forecasts a total of 30,000 GWh of Potential New Work Energy for 2025 and 16,000 GWh for 2017. A detailed sector by sector analysis and results are shown in Chapter 2.

5.2 High Case Forecast Assumptions and Results

The High Case forecast assumes more mines, terminals and plants will be built, and that a higher gas production forecast will occur than assumed in the Mid Case forecast.

Even so, the High Case certainly does not assume all of the dozens of the announced new projects will be built or that the highest projected gas production levels will be met. Rather, the High Case simply discounts those announcements less dramatically than the Mid Case forecast.

Work Energy assumptions:

For activities in the Montney Shale Gas Basin, the High Case forecast uses BC Hydro's High forecast. This is still 30% below the level of customer requests that have already been received.

For the Horn River Basin, the High Case gas production forecast uses BC Hydro's High Forecast. The Northeast Transmission Line to Ft. Nelson and the Horn River Basin is assumed to be completed in 2017, as BC Hydro has signalled.

For the Liard Basin and Cordova Embayment gas fields, even though these basins have a larger area than Horn River, the High Case gas production forecast is assumed to equal the Horn River levels. It still, however, defers production by eight years despite the fact that the current pace of land rights acquisition and drilling indicates they are only about three years behind. It also assumes that the NETL will be extended to the Liard and Cordova Basins three to four years after it reaches the Horn River Basin area.

For LNG, the High Case assumes that only two of the four large LNG terminals that have been announced will be built by 2017. The much smaller LNG terminal is also forecast to be built by 2017. For 2025, the High Case assumes only one of the remaining two announced large projects will be built.

For new mines, the High Case assumes that of the 206 projects that are at various stages of exploration and development, only six will be built by 2017 and five more built by 2025. There is no allowance for the fact that more new potential mine sites will be identified and investigated over the next six to 14 years.

The High Case assumes one alternative transportation fuel plants will be built by 2017 and one more will be built by 2025.

Using the above assumptions the High Case forecasts approximately 48,000 GWh of Potential New Work Energy for 2025 and approximately 28,000 GWh for 2017, broken down as follows;

Table 5-1 Potential Electrifiable Work Energy – High Case (GWh)

Sector	Potential Electrifiable Work Energy Identified	
	2017	2025
Montney Basin O&G	5,046	5,718
Horn River Basin O&G	5,859	9,084
Cordova/Liard O&G	-	5,859
LNG Terminals & Pipelines	9,054	13,372
New Mines	3,691	5,672
Alternative Fuel Plants	4,200	8,400
	27,849	48,105

Electrification Assumptions

Not all of this work energy can be electrified. To adjust for the degree of electrification, each sector's load is discounted for a reasonable degree of electrification.

The degree of electrification for new mines in the High Case has been increased to 90% from the Mid Case assumption of 70%. This reflects mines more aggressively electrifying their operations due to faster transmission extensions and interconnection and more aggressive carbon policy implementation. The degree of electrification for the other five sectors is assumed to be the same for the Mid Case (as detailed in Chapter 2). Overall, the average degree of electrification for the High Case is assumed to increase to 82% from an average of 77% for the Mid Case.

For the High Case, multiplying the increased Degree of Electrification by the increased Potential Electrifiable Work Energy yields a larger Potential Electrified Load for each sector. The results are shown in columns 5 and 6 in the table below:

Table 5-2 Potential Loads after electrification allowance, plus comparison with BC Hydro Load Forecast (GWh)

Sector	Potential Electrifiable Work Energy Identified		% Allowance for Degree of Work Electrification		Potential Load After Allowance For Electrification		Amount Included in Dec. 2010 Load Forecast		Supplemental Potential Electric Load Identified	
	2017	2025	2017	2025	2017	2025	2017	2025	2017	2025
Montney Basin O&G	5,046	5,718	73%	73%	3,704	4,200	1,939	2,359	1,765	1,841
Horn River Basin O&G	5,859	9,084	70%	70%	4,087	6,339	892	1,092	3,195	5,247
Cordova/Liard O&G	-	5,859		70%	-	4,101	-	-	-	4,101
LNG Terminals & Pipelines	9,054	13,372	83%	83%	7,559	11,161	1,100	1,100	6,459	10,061
New Mines	3,691	5,672	90%	90%	3,322	5,105	1,900	1,900	1,422	3,205
Alternative Fuel Plants	4,200	8,400	100%	100%	4,200	8,400	-	-	4,200	8,400
	27,849	48,105	82%	82%	22,871	39,306	5,831	6,451	17,040	32,855

These Potential Electrified Loads for the High Case are compared to the amounts included in the 2010 Load Forecast in order to calculate a new "Supplemental Electric Load Potential" that is incremental to the amounts forecast by BC Hydro in its 2010 Load Forecast.

In summary, the higher number of projects and higher degree of electrification assumed for the High Case creates an additional potential electrical load of approximately 17,000 GWh in 2017 and 33,000 GWh in 2025.

Comparison to Mid Case:

The potential electrical load for the High Case exceeds that of the Mid Case by approximately 11,000 GWh in 2017 and 16,000 GWh in 2025, and is shown by sector below:

Table 5 – 2: Comparison of High Case to Mid Case for Potential Load - after allowance for electrification (GWh)

Sector	HIGH CASE Potential Load After Allowance For Electrification		MID CASE Potential Load After Allowance For Electrification		DIFFERENCE Potential Load After Allowance For Electrification	
	2017	*2025*	*2017*	*2025*	*2017*	*2025*
Montney Basin O&G	**3,704**	**4,200**	**2,997**	**3,483**	**707**	**717**
Horn River Basin O&G	**4,087**	**6,339**	**2,659**	**4,027**	**1,428**	**2,312**
Cordova/Liard O&G	**-**	**4,101**	**-**	**1,334**	**-**	**2,767**
LNG Terminals & Pipelin	**7,559**	**11,161**	**3,956**	**7,559**	**3,603**	**3,602**
New Mines	**3,322**	**5,105**	**2,331**	**3,140**	**991**	**1,965**
Alternative Fuel Plants	**4,200**	**8,400**	**-**	**4,200**	**4,200**	**4,200**
	22,871	**39,306**	**11,943**	**23,743**	**10,928**	**15,563**

The higher number of projects and higher degree of electrification assumed for the High Case almost doubles the potential electrical load in 2017, and increases it by two-thirds in 2025, when compared to the Mid Case.

5.3 Very High Case

It should be noted that the High Case still does not assume that all announced projects will be built nor the highest gas production projections will be met.

For instance, for Montney Basin, if all customer requests received by BC Hydro were to be serviced, the load there would increase by more than 40% over the High Case. If the number of included functions to be electrified increases to the same level as BC Hydro forecasts for Horn River (i.e. from 0.115 MW/MMcfd to 0.165 MW/MMcfd) the load would increase by another 43%. The increases from these two effects compound each other.

For Liard/Cordova, if the electrification percentage was assumed to increase to the same level as Montney, from 70% to 74%, the load would increase another 6%. More significantly, if drilling and processing in the Liard/Cordova basin continues on its current fast pace, it will require work energy much faster than the High Case assumes. The High Case assumes it will follow Horn River by eight years, but the graphs in Figure 2.3 - 3 show the pace of petroleum natural gas rights payments for Liard/Cordova is following Horn River by only three to four years.

If all four large LNG plants that have been announced are built, instead of the three assumed in the High Case, an additional load of approximately 3,000 GWh would be required. This level of LNG production would require new pipelines to be built and more solid estimates of huge amounts of northeast shale gas reserves. Also, Asian LNG markets would also have to remain strong.

If more than 12 new mines start up in the next 14 years more electricity will be required than forecast for the High Case. Currently, there are 206 mines at various stages of exploration and development. If commodity prices stay anywhere near current high levels, more of them are likely to get built, thereby requiring more energy. If BC Hydro extends the NWTL from Bob Quinn to Dease Lake, several additional mines that are already advancing would use clean renewable energy from the grid rather than diesel power.

5.4 Summary

There are new mines and terminals that have already been announced and higher gas production forecasts that are not included in the High Case that, if built, would result in even higher load growth than the approximately 23,000 GWh in 2017 and 39,000 GWh in 2025 in the current High Case.

The High Case forecast is possible, but not very probable. It would require more forceful implementation of the fuel switching and transmission expansion elements of the *Clean Energy Act* and *Greenhouse Gas Reduction Targets Act*.

The Very High Case is very unlikely, but it puts the Mid Case forecast in perspective by showing that it assumes only a small proportion of the new projects announced will get built and uses gas production projections much lower than others that have been published.

Chapter 6: Recommendations

While it is hard to forecast exactly how many mines, LNG terminals and alternative fuel plants will be built or what level of gas production will occur in the three northeast gas basins, it is certain that whatever projects are built will use some form of energy to power their activities.

If these activities are not driven by clean renewable electricity supplied by the main BC Hydro grid, then it is highly probable their work energy needs will be met using fossil fuel energy. This will increase greenhouse gas emissions.

Drill rigs, pipeline compressors and processing plants in the Horn River shale gas basin, for example, do not currently have access to BC Hydro's grid-based electricity service. They use diesel and natural gas to produce their energy. Diesel- and gas-fuelled energy creates GHG emissions. These emissions could be substantially reduced if grid-based electricity, 90% of which comes from clean and renewable energy sources, was readily available. If it is not available, the drilling, compressing and processing won't stop. It will simply be driven by more and more fossil-fuelled energy sources.

The BC *Clean Energy Act (2010)* includes objectives to:

> *reduce BC greenhouse gas emissions … by 2020 and for each subsequent calendar year to at least 33% less than the level of those emissions in 2007 … and by such other amounts as determined under the Greenhouse Gas Reduction Targets Act*

and

> *to encourage the switching from one kind of energy source or use to another that decreases greenhouse gas emissions in British Columbia.*

This report recommends government and BC Hydro implement GHG reduction measures, including fuel switching (i.e. from diesel generation to grid-based clean renewable electricity), and accelerate transmission extensions (i.e. NETL) and interconnections (to new mines) as fully and promptly as is reasonably possible.

Chapter 7: Summary

In the ten months since BC Hydro's December 2010 Load Forecast, the dozens of announcements of new mines, LNG terminals, alternative fuel plants and higher shale gas production projections have increased the potential work energy requirements for six major industrial sectors significantly.

The potential new work activities identified in all six sectors will consume some form of energy. Not all will be electrified. However, if these energy needs are not served by clean renewable electricity supplied by the main BC Hydro grid, then it is highly probable they will be served by fossil fuels, with all the associated greenhouse gas emissions.

BC Hydro and government should do all that is possible to encourage the maximum amount of electrification of these potential new loads, and to accelerate the extension of the transmission system to deliver the required energy to these industrial customers.

Based on specific Mid Case assumptions of more projects, gas production and degrees of electrification, the potential new electrified loads could total approximately 12,000 GWh and 23,700 GWh in 2017 and 2025 respectively, comprised of the following components:

Table 7-1 Potential New electrified loads, by sector (GWh)

Sector:	***2017***	***2025***
Montney Basin natural gas activities	2,997	3,483
Horn River Basin natural gas activities;	2,659	4,027
Liard/Cordova Embayment Basin natural gas activities;	0	1,334
New Liquefied Natural Gas terminals and pipelines;	3,956	7,559
New mines; and	2,331	3,140
New plants to produce alternative transportation fuels	0	4,200
Total	**11,943**	**23,743**

These Mid Case totals are higher than the BC Hydro December 2010 forecast for the same sectors by approximately 6,100 GWh in 2017 and 17,300 GWh in 2025.

Using High Case assumptions, with a higher proportion of already announced mines and terminals and higher, but not the highest, gas production forecasts, the total potential new load could almost double to approximately 22,900 GWh in 2017, and increase by two-thirds to approximately 39,300 GWh in 2025.

For CanWEA's BC WindVision, this report suggests the Mid Case forecast of 23,700 GWh of load growth from these sectors for 2025. If this load is added to the rest of the industrial loads in BC Hydro's 2010 Load Forecast, the total industrial load in 2025 is projected to be close to 45,000 GWh.

These results are shown in the following graph, which layers the Mid Case loads for these six sectors on top of the load growth forecast for BC Hydro's other industrial loads, like forestry, existing mines and other industrial sectors (shown in dark green at the bottom of each load stack). This report did not review those other sectors and the graph is not to scale.

Figure 7-1 Potential Electrified Loads for Six Sectors and other industrial sectors loads