Thursday, May 16th 2013

**The Industrial Rates Review Panel**
**Messrs. Chris Trumpy, Peter Ostergaard and Tim Newton**

C/o Mr. Scott Barillaro
Director, Transmission and Industrial Electricity Policy
Ministry of Energy, Mines and Natural Gas
4th Floor, 1810 Blanshard Street
Victoria, BC, V8T 4J1
scott.barillaro@gov.bc.ca

Dear Sirs:

**Re: Industrial Electricity Policy Review Task Force**
**Consultation Summary, DRAFT, May 1st 2013**

CEBC thanks the Panel for the opportunity to provide comments on your DRAFT Summary dated May 1st 2013

Overall we believe this Summary accurately assesses our position on the various topics presented to the stakeholders – with one significant exception in your Other Comments on page 7.

"***Projected BC Hydro Surplus***
Stakeholders were aware of BC Hydro's projected near-term energy surplus from BC Hydro's updated Load/Resource Balance. There was consensus that this represented a potential cost to ratepayers given weak export markets and that BC Hydro should take prudent action to reduce its energy surplus as quickly as possible."

We do not agree that there is a consensus nor do we believe there is a significant surplus of electricity in B.C. As evidenced by the following graph from BC Hydro's Site C application, there is a negligible surplus that is only created if BC Hydro continues to spend money on Power Smart. Why would this money be spent to create a surplus? The projected demand does not include LNG electric load and apparently the corresponding electric load in the natural gas fields. One large LNG facility at full build out would convert about 3.3 billion cubic of natural gas per day into LNG. The current daily production of natural gas in B.C is about 3.3 billion cubic feet of natural gas. It is inconceivable that if natural gas production in B.C.is doubled, tripled or even quadrupled, there will be almost no significant increase in B.C. Hydro's electrical demand.

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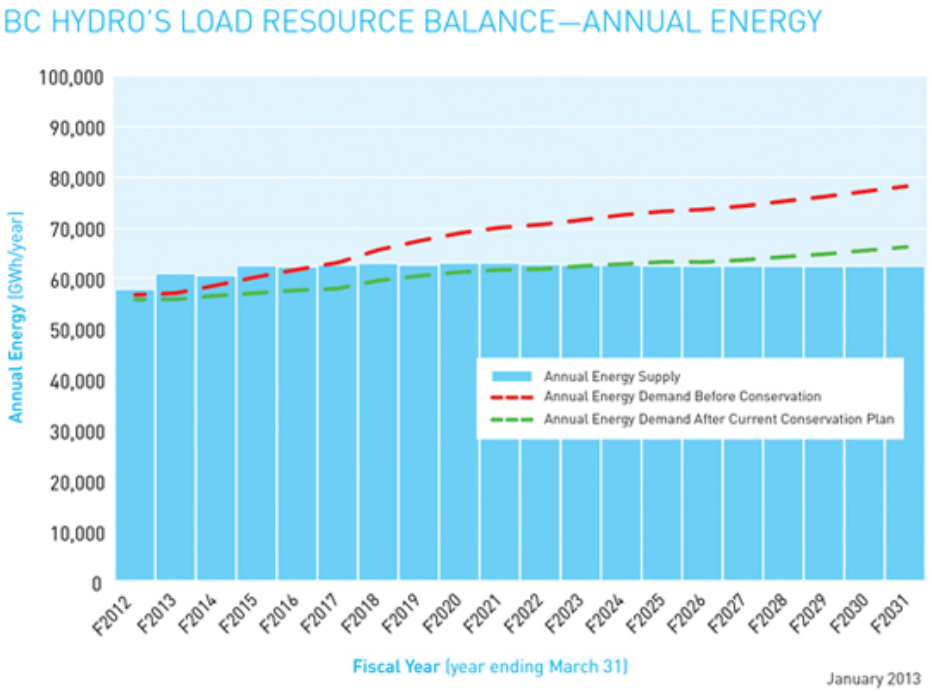
The reality is that the Province has significant resource development potential (LNG projects in the Kitimat and Prince Rupert regions and mines of which two are being built and another 30 currently have applications submitted with the BC Environmental Assessment Office).




We attach our DRAFT Report "***Potential Industrial Load Growth in Northern B.C***". together with a May 9th Edmonton Journal article that highlights the interest by Alberta's ATCO Group to build a transmission line from Alberta into northeast BC to satisfy the electricity requirements in our Province's natural gas fields.

CEBC respectfully submits there needs to be a much more fulsome review of the facts by an independent agency before any declaration of a consensus or surplus can be made.

We welcome your review of these comments.

Sincerely yours,

Paul Kariya
Executive Director

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354 - 409 Granville Street | Vancouver, BC V6C 1T2, Canada | Office: 604.568.4778 | Fax: 604.568.4724 | www.cleanenergybc.org

# Potential Industrial Load Growth in Northern B.C.

## Introduction

In 2011, BC Hydro stated that there is *"Unprecedented load growth potential in the North, driven by shale gas and mining developments including Montney, Horn River basin, North Coast LNG and Mining"* [1] And in 2012, "*BC Hydro is anticipating some of the most dramatic single-industry load growth in a discrete area that it has experienced in recent history*"[2]

In 2013, BC Hydro's latest load forecast states; *"The energy Load Resource Balance in Table 5.8 shows that … there is a need for energy beginning in F2024."*[3] The Table supports that statement by forecasting a surplus of energy in B.C. for the next 10 years, until 2023.

How can there be unprecedented and dramatic load growth potential but no plan to acquire any new energy supply for 10 years?

This document focuses on potential industrial load growth in northern B.C. It is the largest area of potential load growth. There is additional potential load growth in southern B.C. plus there is load growth expected in the residential and commercial sectors – but that is not included in this forecast.

The first 7 sections of this report are a preliminary forecast of northern industrial load growth for seven sectors. Section 8 shows these seven sectors potential load growth could total 35,000 GWh/yr by 2026. The last two sections are excerpts from BC Hydro's two recent load forecasts.

## Northern Industrial Load Growth Forecast

Electricity demand in B.C. is forecast to soon increase significantly to serve several large proposed energy-intensive industrial facilities that have been announced in the last two years.

The majority of these facilities are to be located in northern B.C. They are grouped in the following sectors:

1. Liquefied natural gas export terminals
2. Mineral mines
3. Port expansions
4. Oil terminals and pipelines
5. Shale gas basin activities in North East B.C.
6. Synthetic Fuel Plants
7. Coal mines

[1] BC Hydro power point slide labeled "Meeting Demand" from their presentation "Meeting New Power Needs" delivered September 26, 2011
[2] BC Utilities Commission hearing on BC Hydro Application for a CPCN for the Dawson Creek Area Transmission Project
[3] Page 5–4, Volume 1, Need for the Project, Site C Energy Project Environmental Impact Statement, February, 2013



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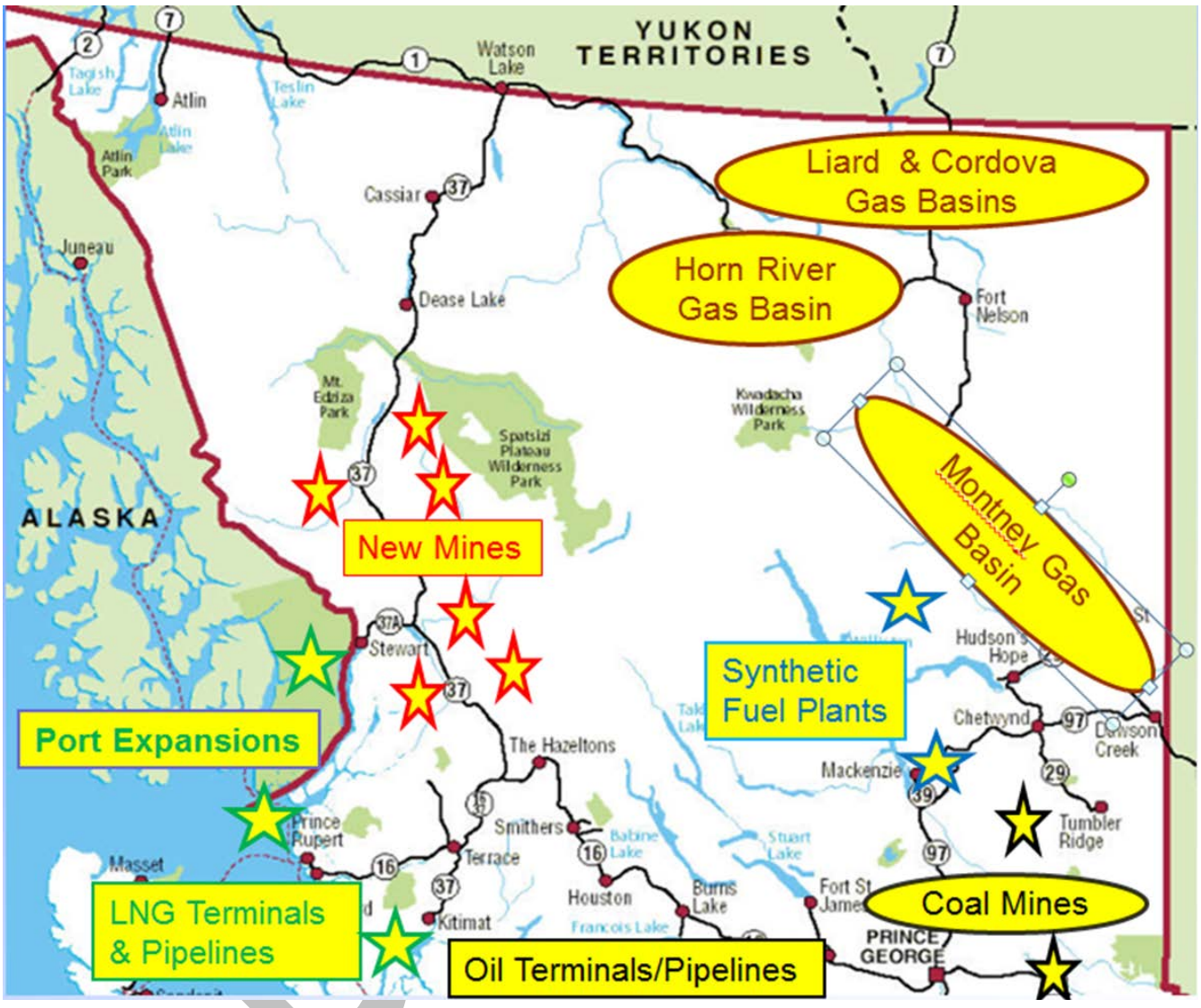
*Figure 1: Map of selected large industries planned for Northern B.C*




**1. Liquefied Natural Gas**

The sector offering the largest potential load growth is the Liquefied Natural Gas (LNG) sector.

Several world-scale, multi-billion dollar LNG export terminals are proposed on the North Coast of B.C. They are located in Kitimat, Prince Rupert and Kitsault.

The LNG terminal proposed for Kitimat by Chevron/Apache is shown in Figure 2. Chevron states the terminal will require 400 MW (~3,700 GWh/year). If only the non-compression load of the terminal is powered by electricity that would be about 550 GWh/year.

A list of 9 proposed LNG terminals, along with the project sponsors, locations, production levels and targeted Commercial Operation Dates is shown in Figure 3.

*Figure 2. Artists Rendition of Proposed LNG plant in Kitimat*

*Figure 3. List of 9 Proposed LNG Terminals*

| Plant # | Name | Sponsor Companies | Location | Initial Phase MT/yr | Initial Phase COD | Final Plant MT/yr | Final Plant COD |
|---|---|---|---|---|---|---|---|
| LNG 1 | Kitimat LNG | Chevron & Apache Canada | Kitimat, Bish Cove | 5 | 2017 | 10 | 2018 |
| LNG 2 | BC LNG Co-operative | Haisla First Nation & LNG Partners LLC | Kitimat, Douglas Channel | 0.7 | 2015 | 0.9 | 2017 |
| LNG 3 | LNG Canada | Shell, Mitsubishi, KOGAS, PetroChina | Kitimat | 12 | 2019 | 24 | 2025 |
| LNG 4 | Pacific Northwest LNG | Petronas, Progress Energy | Prince Rupert, Lelu Island | 7.6 | 2018 | 18 | TBD |
| LNG 5 | BG LNG | BG Group, Spectra Energy | Prince Rupert, Ridley Island | 18 | 2019 | 18 | 2020 |
| | | | **Sub Total A** | **43.3** | **by 2019** | **70.9** | **by 2025** |
| LNG 6 | XON/Imperial | Exxon, Mobil, Imperial Oil | Prince Rupert or Kitimat | 10 | | TBD | |
| LNG 7 | Nexen /INPEX | Nexen Energy, INPEX | Prince Rupert | TBD | | TBD | |
| LNG 8 | Kitsault LNG | Not identified | Kitsault | TBD | | TBD | |
| LNG 9 | PNG LNG | AltaGas and Idemitsu | Kitimat | TBD | 2017 | TBD | |
| | | | **Sub Total B** | **35** | | **56.7** | |
| *Notes:* | | | **Total Potential** | **78** | | **128** | |

BC Hydro's IRP forecasts the loads of the first three LNG terminals as follows:

*Figure 4: BC Hydro forecast of loads for LNG 1, 2 and 3*

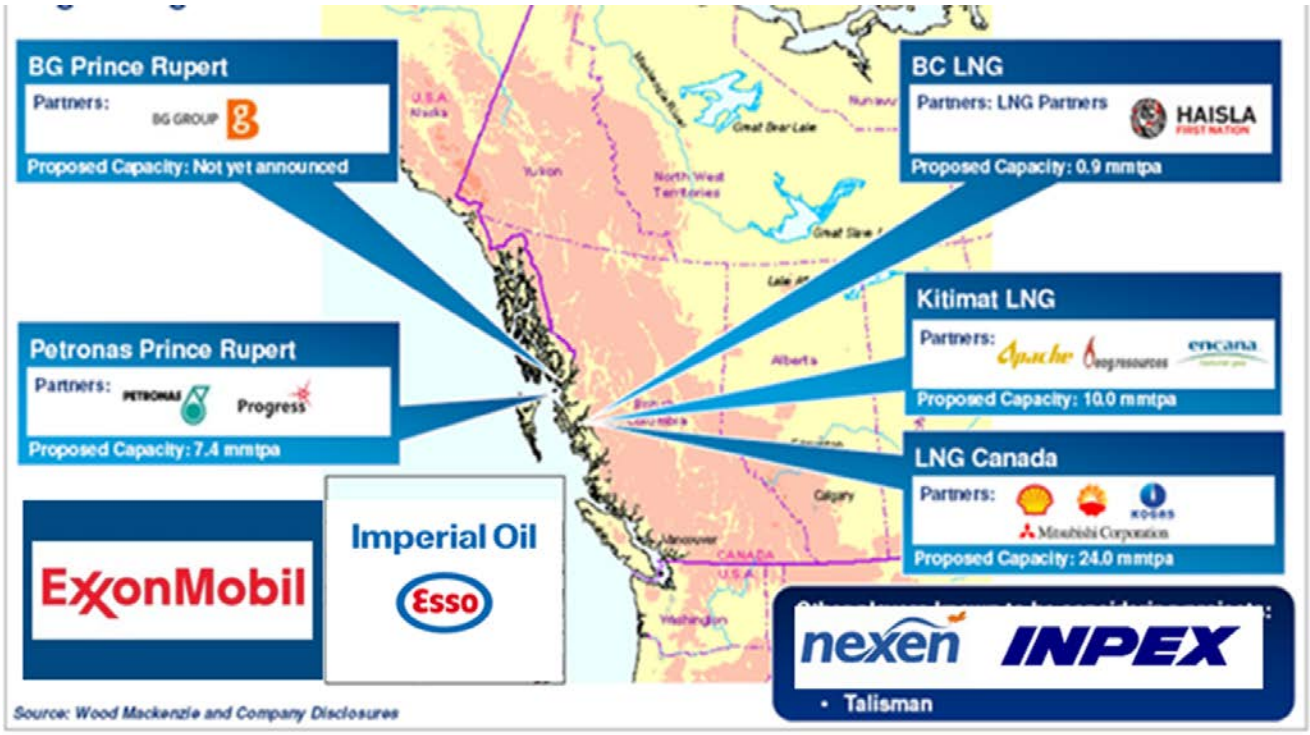
| *Energy Load (GWh/yr)* | *F2017* | *F2021* | *F2026* | *F2031* |
|---|---|---|---|---|
| LNG 1 & 2 | 3,800 | 5,281 | 5,280 | 5,281 |
| LNG 3 | - | 9,617 | 12,823 | 12,822 |
| Total | 3,800 | 14,898 | 18,103 | 18,103 |

Fully powering these three terminals would require 18,000 GWh/yr. Powering just the non-compression load of these three terminals would require 2,700 GWh/yr (15% of the total terminal load).

The sponsor companies developing the LNG terminals have made many investments in acquisitions and commitments to build billions of dollars of terminals and pipelines in B.C. The

sponsor companies represent some of the largest LNG companies in the world, as shown on the map in Figure 5.

*Figure 5: Map of Proposed LNG terminals*




To date, the National Energy Board has approved three projects; LNG 1, LNG2, and LNG 3.

Since BC Hydro issued the draft IRP in May, 2012, many major announcements of new LNG terminals and advancements of previously announced projects have been made, including:

July, 2012: TransCanada signs $5 billion pipeline deal

September, 2012: Petronas purchases option for Prince Rupert site for $10 billion LNG terminal

Dec, 2012: Imperial Oil and Exxon plan to export LNG with $3 bil. acquisition of gas producer

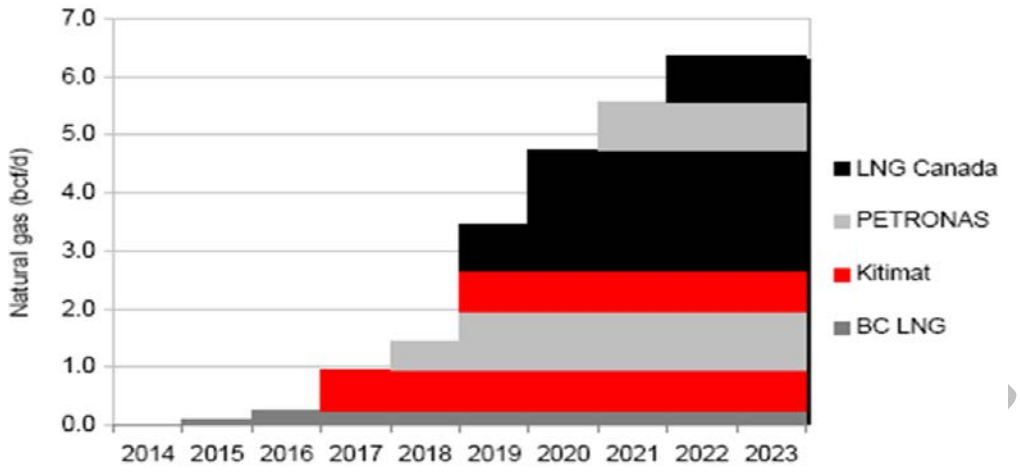
April 1, 2013: Japanese government to guarantees $10 billion to boost the development of gas in B.C.

April 10, 2013: Four multi-national O&G companies file EoIs on Grassy Point, north of Prince Rupert

A schedule of the expected LNG terminals consumption of natural gas is shown in Figure 6. If three of these terminals proceed they will require 6 bcf/d. That will result in tripling B.C.'s gas production. This will result in hundreds more drill rigs, several processing plants, and two new

1,000 km pipelines. They all require energy to operate. This is described in Section 5 on North Eastern Gas Basins Activities.

*Figure 6: Schedule of Natural Gas consumption for the first 4 LNG terminals*




Source: Company reports, Macquarie Research, September 2012

The underlying economic factors driving new LNG export terminals is the large spread between North East B.C. gas costs and Asian LNG prices. These can be seen in Figure 5 and 6.

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*Figure 7: Increasing spread between oil and gas prices from 2005 to 2012*

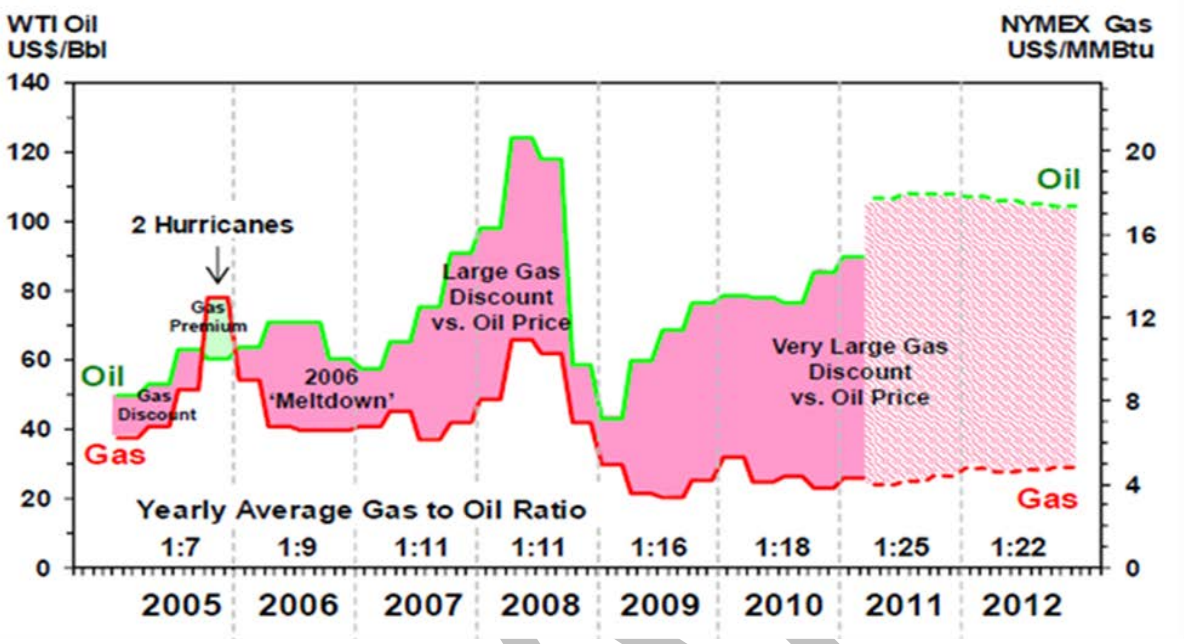
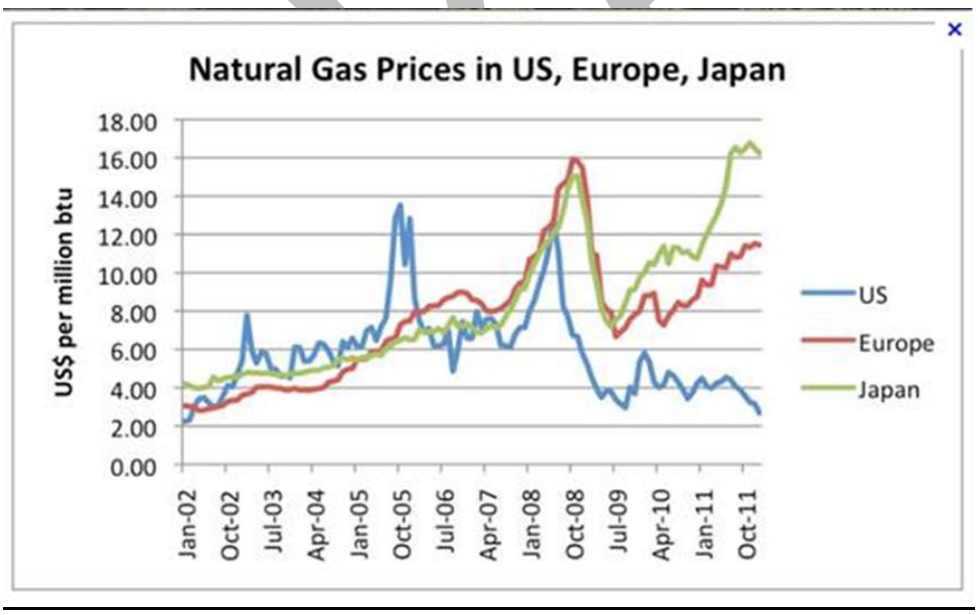



*Figure 8: Natural gas prices in the U.S., Europe and Japan*



## 2. Mines

Some mines can be big power users. B.C.'s Highland Valley Copper mine is BC Hydro's largest single customer, consuming 930 GWh/year.

*Figure 9: Highland Valley Copper Mine – BC Hydro's largest industrial customer!*

*Figure 10: Process Flow Sheet for the Turnagain Copper and Gold Mine proposed for North Western B.C.*

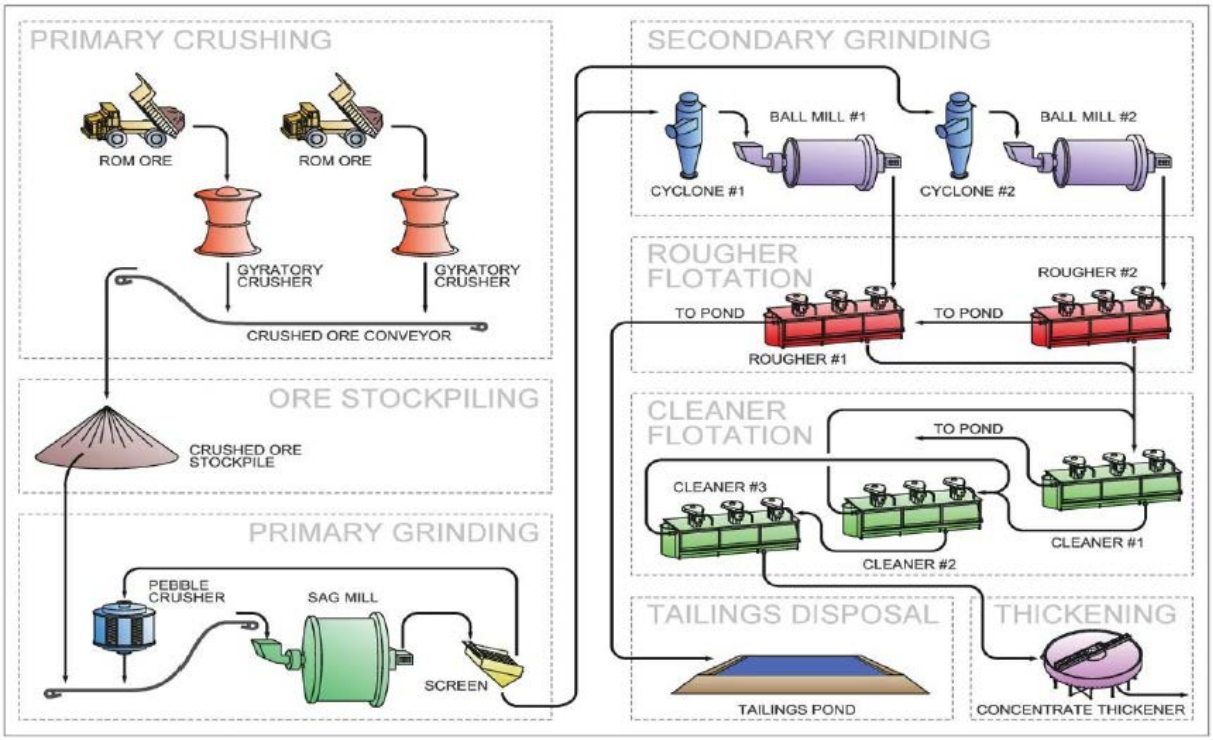
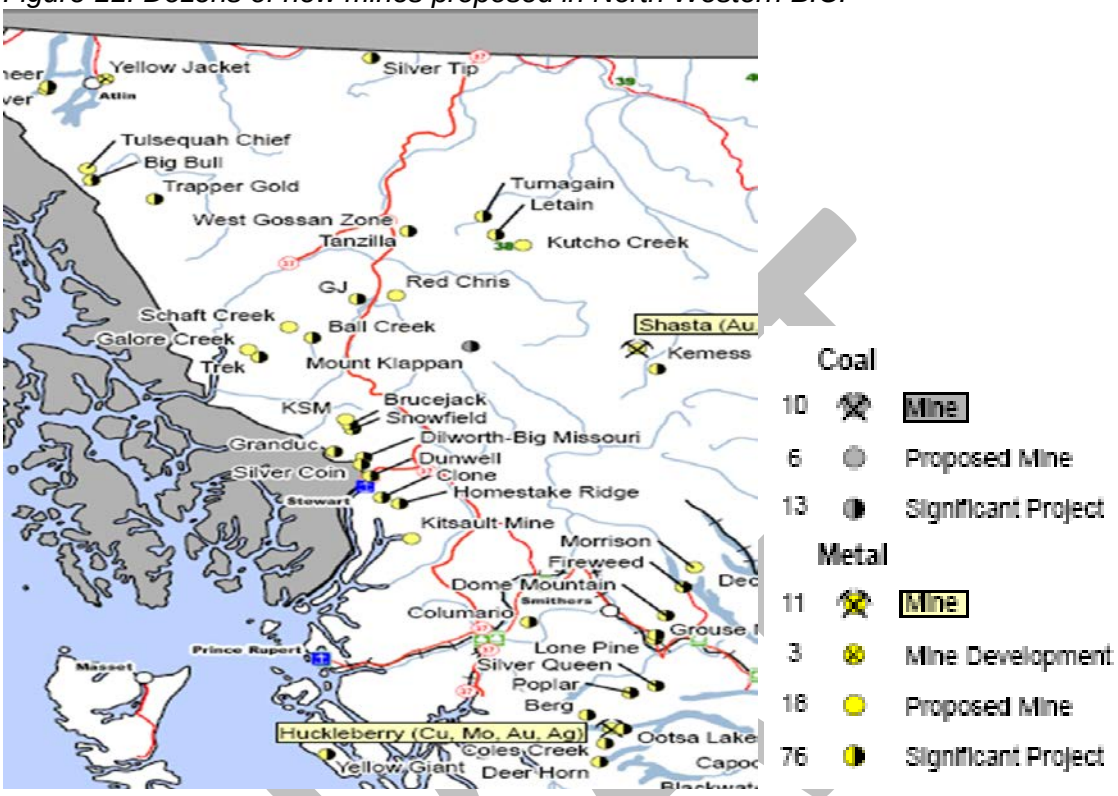


*Figure 11: Dozens of new mines proposed in North Western B.C.*




In 2011, there were 89 exploration projects and $220 million spent on exploring the northwestern region of B.C.

The mining industry was prominently featured in the 2011 BC Job Plan wherein the Premier announced the commitment to eight new mines and the expansion of another nine operating mines by 2015. Assuming an average of 300 GWh/year per new mine and 100 GWh/year per mine expansion, that totals 3,500 GWh/year of additional mining load.

The Association of Mineral Exploration of BC press release of February, 2013states; "*Mineral exploration expenditures are up again this year to $680 million, which is 47 percent higher than 2011 — a record year.*"

In March, 2013 BC Hydro announced the extension of the North West Transmission Line another 93 km, to connect Red Chris Mine. The mine load is expected to be over 400 GWh/year.

BC Hydro draft 2012 IRP states: *"While the full potential of the mining loads interconnecting to BC Hydro's committed Northwest Transmission Line, which comes into service in F2015, far exceeds the estimated 465 MW capacity of the line, the mining loads have been capped at the*

*estimated capacity of the line. The mid Load Forecast includes approximately 200 MW of load in the NTL region, which is the probability weighted sum of the forecasted mining loads in this region. This load is forecasted to be approximately 70 GWh/year and 20 MW in F2014 growing to approximately 2,000 GWh/year and 270 MW by F2018."*

BC Hydro's 2012 draft IRP forecasts electricity sales to mines to double by 2016 and to reach 6,700 GWh/yr by 2021.

**3. Port Expansions**

Significant expansions are planned for three ports on the North Coast; Prince Rupert, Kitimat, and
Stewart. They are deep water ports that are relatively close to northern China and Japan and Korea.

*Figure 12: Map of Shipping Routes to Northern Asia*

Over $6 billion is planned to be invested in new terminal developments in Prince Rupert.

*Figure 13: Port of Prince Rupert*

Ridley Terminals near Prince Rupert, is currently undergoing expansions to more than double its annual shipping capacity to 25 million tonnes by the end of 2014.

*Figure 14: Ridley Terminals*

*Figure 15: Container ship berthing at Prince Rupert Fairview Terminal*

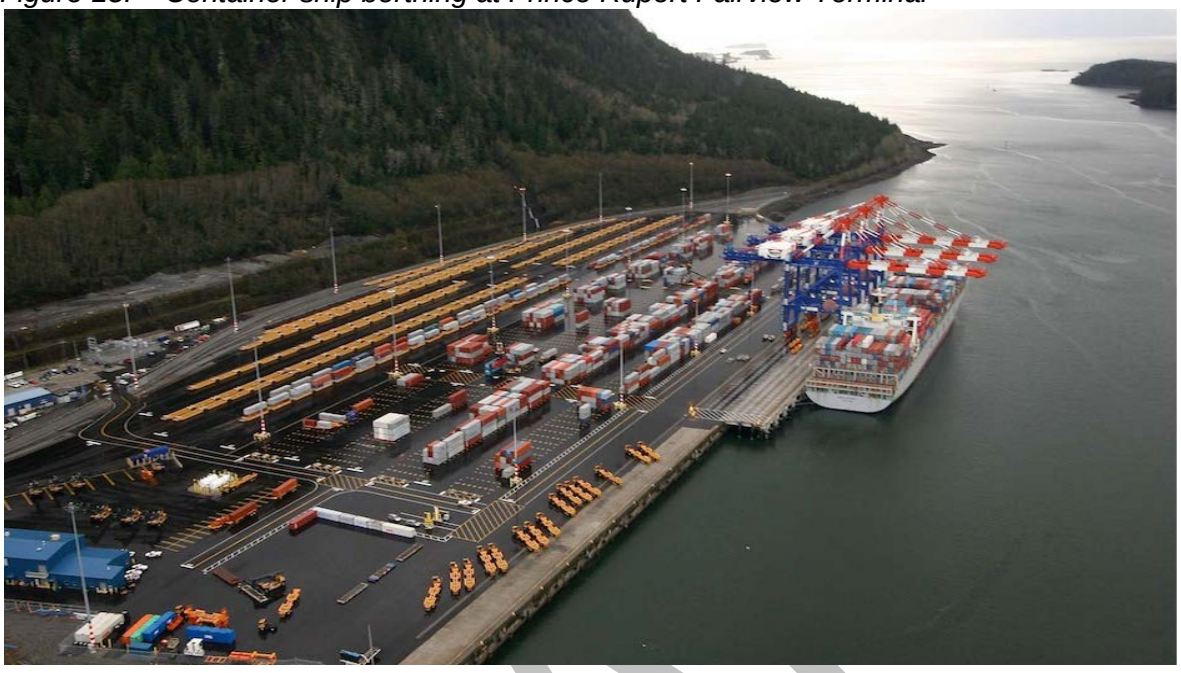


*Figure 16: Port of Kitmat*

## 4. Oil Pipelines and Refineries

The following 6 oil pipelines, terminals and refineries are planned:

1. Enbridge's Northern Gateway Crude Oil Pipeline and Terminal,
2. Enbridge's Northern Gateway Condensate Pipeline,
3. Transmountain's TMX North Spirit Condensate pipeline[4],
4. Pembina's Kitimat to Summit Lake Pipeline,
5. Kitimat Clean Ltd., Oil Refinery, and
6. Kitsault Oil Refinery

*Figure 17: Photograph of a mock-up model of the Enbridge Northern Gateway.*[5]

[4] BC Major Projects Inventory, 2012
[5] Photograph by: Canadian Press , Postmedia News

*Figure 18: Oil pipeline similar to proposed Northern Gateway project to carry bitumen from Alberta to Kitimat, B.C*[6]

**5. North East Gas Basin Activities**

The Conference Board of Canada estimates that the annual investment in North Eastern B.C. gas basins is forecast to more than quadruple in the next 10 years, increasing from $1.8 billion/year to $7.4 billion/year.

BC Hydro stated; *"BC Hydro is anticipating some of the most dramatic single-industry load growth in a discrete area that it has experienced in recent history."*[7]



[6] Photograph by: Candace Elliott, file photo, edmontonjournal.com
[7] Globe and Mail, October 10, 2011, BC Hydro says Clark's jobs plan needs huge power hike

*Figure 19: Map of Shale Gas Basins*

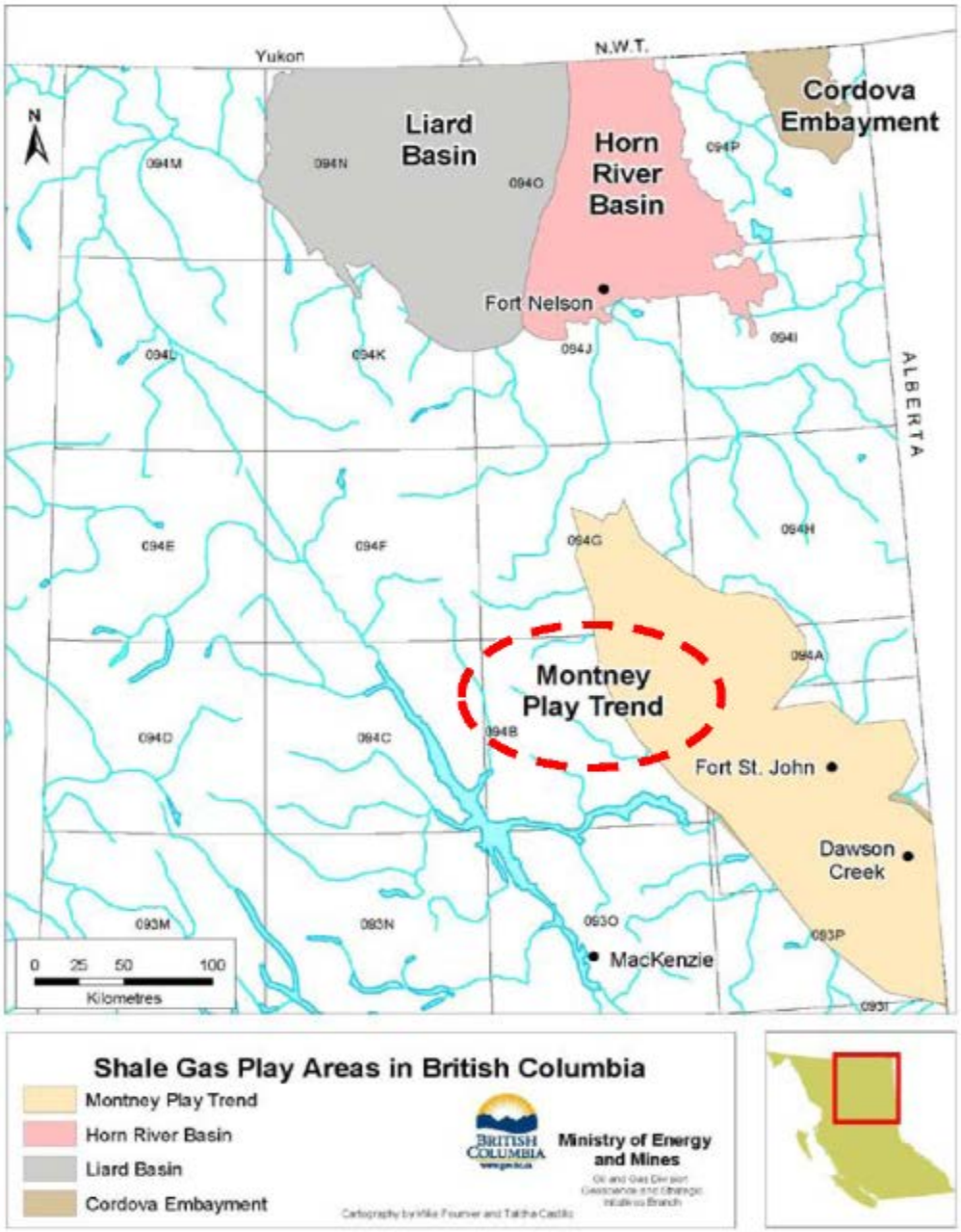
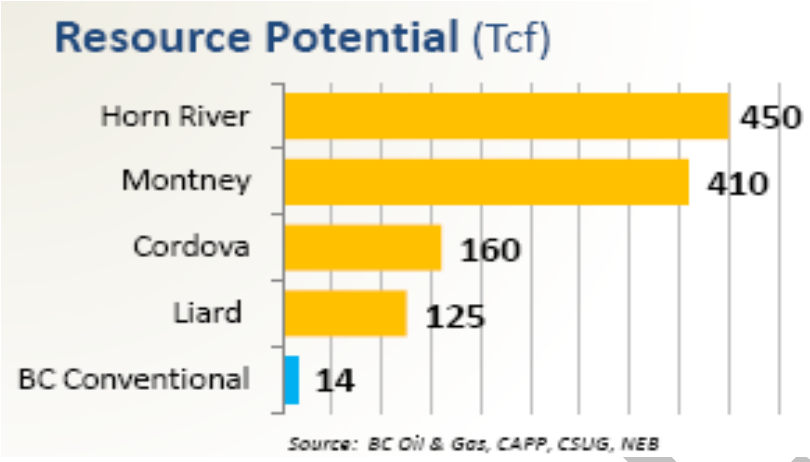


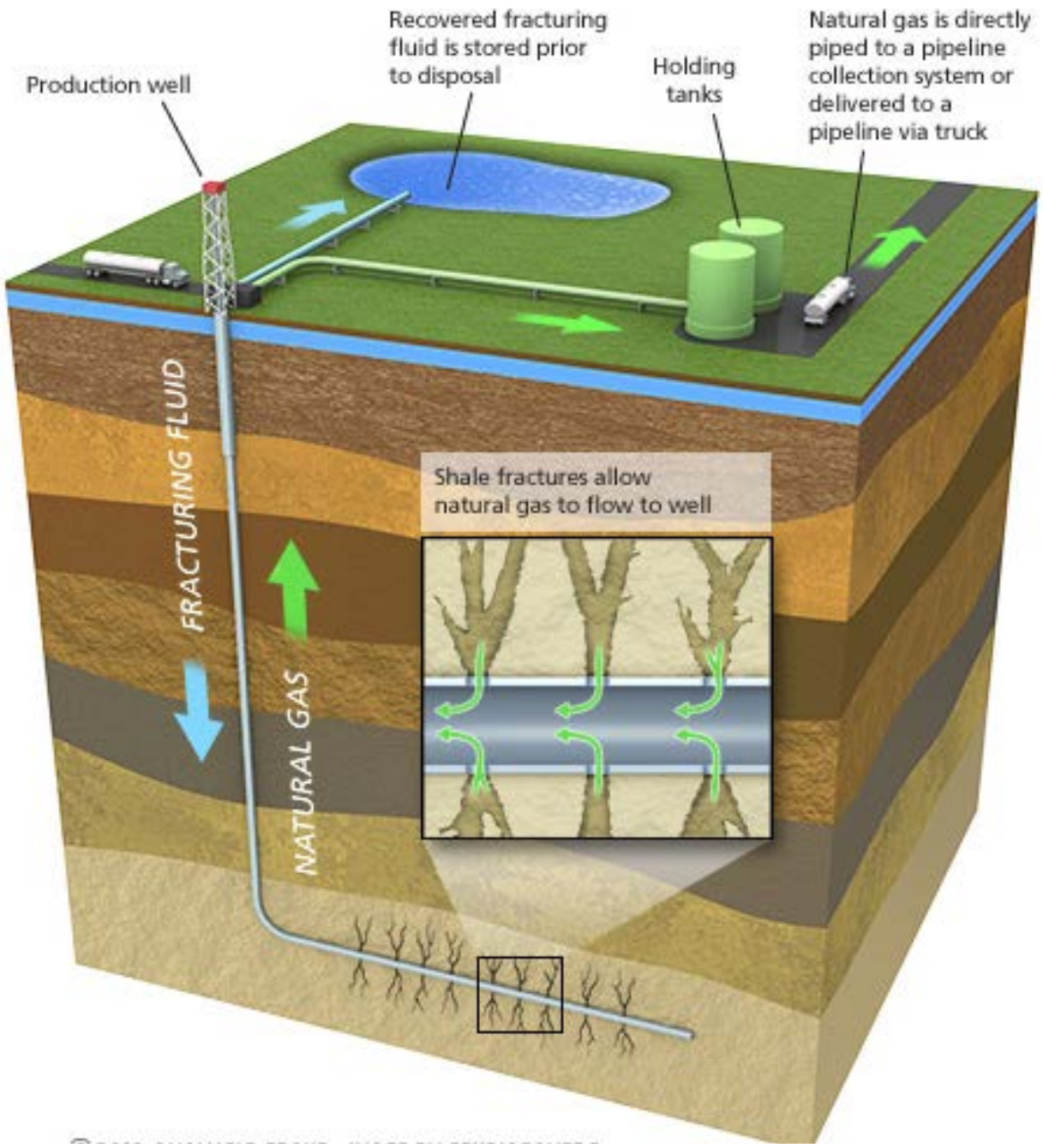
*Figure 20: Potential of Shale Gas vs Conventional Gas in B.C.*




The upstream activities fall into three functions; Extraction, Processing and Pipelining. All are energy intensive.

*Figure 21: An Apache Corp. gas extraction drill site in the Horn River Basin*

*Figure 22: Diagram of several steps in the fracking process - each step requiring energy*

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To date, few shale gas drill rigs in B.C. have used grid-based electricity. Most use diesel gen-sets. Recently, shale gas drill rigs in the U.S.A. are increasingly using grid-based electricity[8] as shown in the second figure below.

*Figure 23: Nexen shale gas drilling site in North East B.C. – using diesel generators*

[8] Power Forecast 2012: Williston Basin Oil & Gas Related Electrical Load Growth Forecast, Kadrmas, Lee & Jackson Inc.

*Figure 24: Electrified Drill Rig in Barnett Shale Gas Basin – using 1.5 MW from nearby transmission lines.*

*Figure 25: Encana Gas Processing Plant, east of Fort Nelson*

*Figure 26: TransCanada Compressor Station*

*Figure 27: BC Hydro Load Forecast for Montney Gas Basin from draft 2012 IRP*

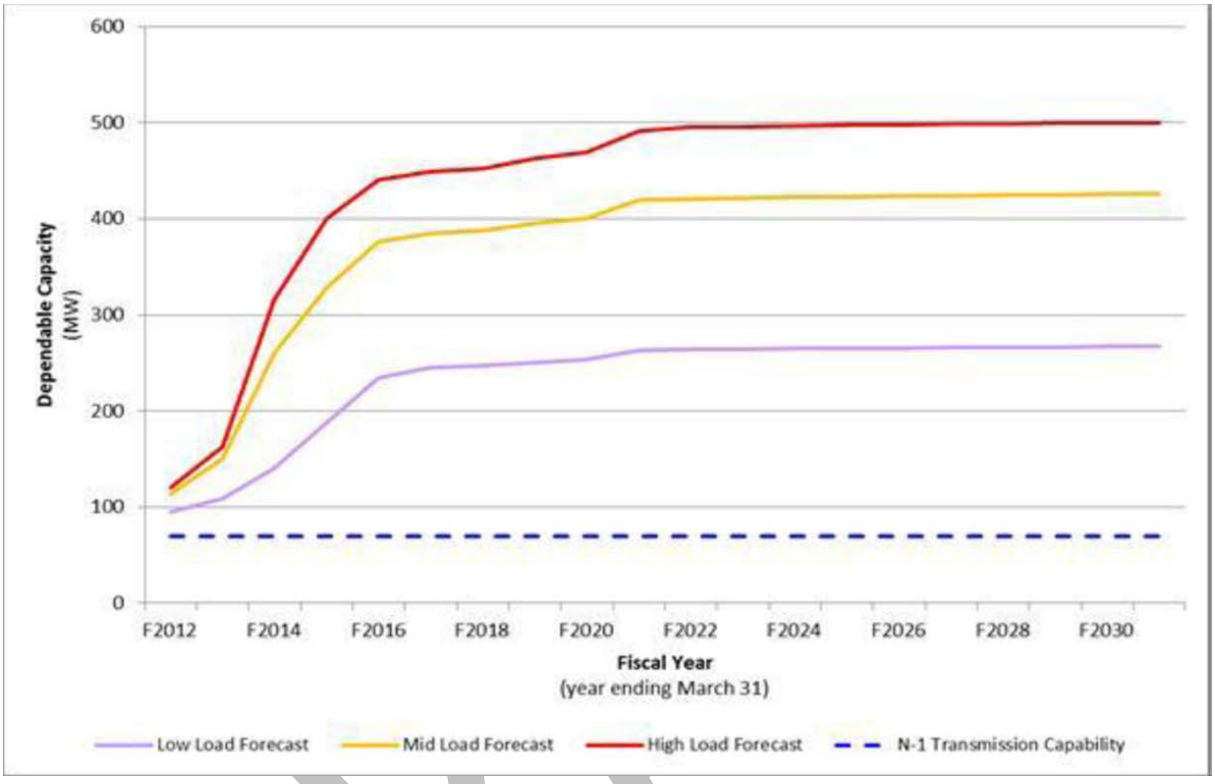
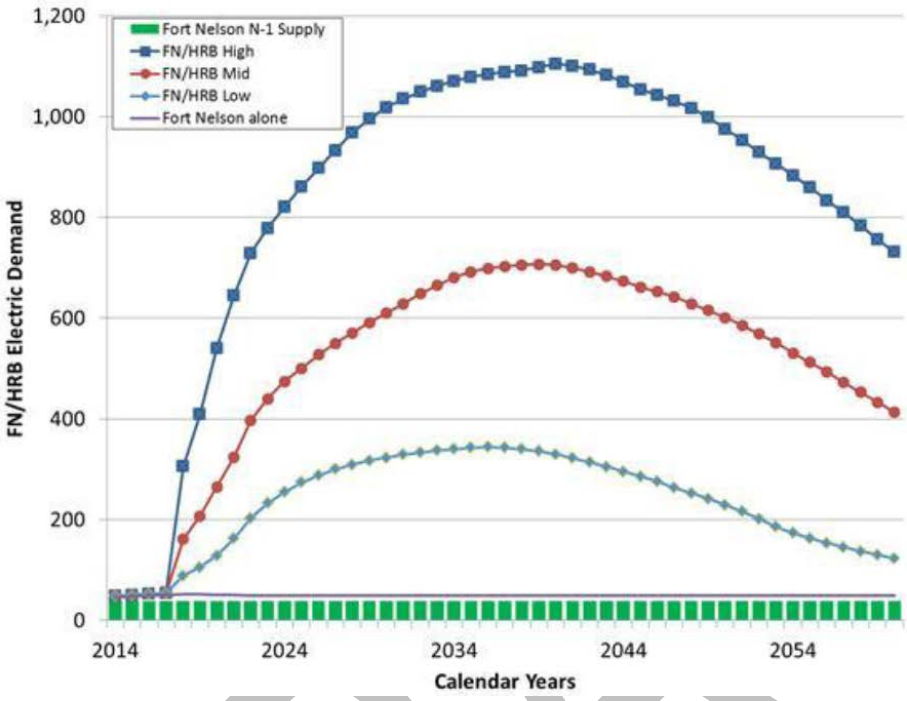


*Figure 28: BC Hydro Load Forecast for Horn River Gas Basin from draft 2012 IRP*




Typically about 500 new drill rigs are installed in B.C. each year. They each require about 1.0 MW and operate about 80% of the time. If half were electrified they would require 2,700 GWh/yr. If that pace of installation and electrification continued, by 2026 they would require a total of over 27,000 GWh/yr.

The Canadian Association of Petroleum Produces states; "*The oil and gas industry is interested in developing facilities that use electricity instead of natural gas as their source of power – particularly in the Montney Basin.*"[9] CAPP describes *"a number of industrial consumers were seeking 176 MW (~1,500 GWh/year) of electrical power to operate facilities in the Dawson Creek area."*

**6. Synthetic Fuel Plants**

Two companies have announced plans in North East B.C. to build multi-billion dollar plants that would produce (or synthesize) transportation fuels using feedstock other than petroleum oil, mainly natural gas, coal and CO2. Those plants involve:

[9] Canadian Association of Petroleum Producers submission to Industrial Electricity Policy Review Task Force, May, 2013

1. Blue Fuel Energy (methanol and /or synthetic gasoline) and
2. Sasol Gas-To-Liquids (GTL) technology.

A multi-billion dollar Blue Fuel plant has been proposed near Chetwynd, B.C. It would use the CO2 derived from the processing of natural gas as a feedstock to make various fuels that are used in transportation vehicles. It would require 4,200 GWh/year of electricity.

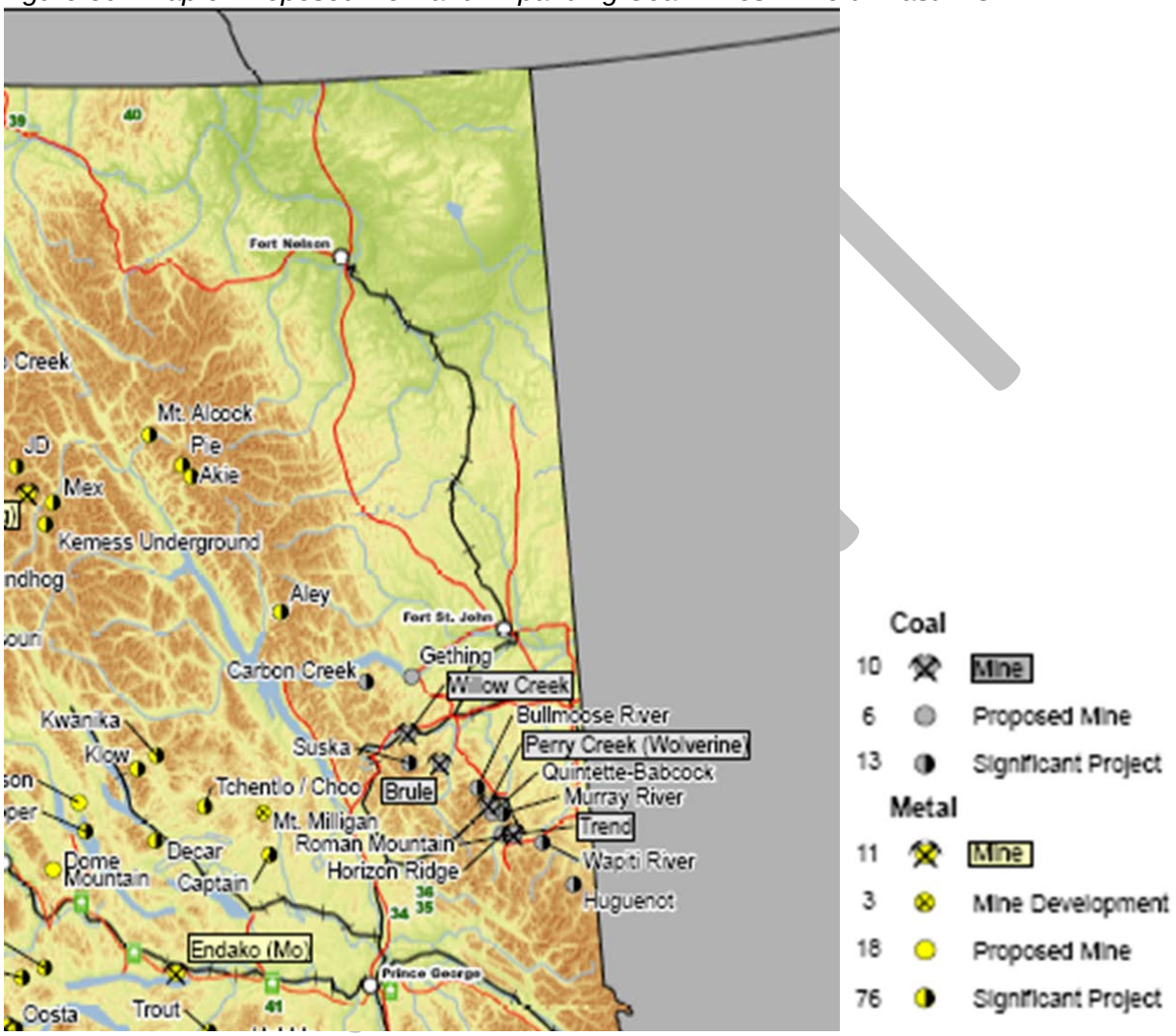
Sasol Ltd., a South African company with a long history of producing liquid fuels from coal using the proven Fischer-Tropsch process, has announced interest in a multi-billion dollar plant near B.C.'s shale gas fields. The proposed SasolFuel plant will process natural gas into liquid fuels.

*Figure 29: Sasol Gas-to-Liquids Complex planned for Louisiana.*

**7. Coal Mines in North East B.C.**

Nine new coal mines are planned for North East B.C. (NEBC). Two existing coal mines in NEBC are also being reopened.

*Figure 30: Map of Proposed New and Expanding Coal Mines in North East B.C.*




BC Hydro's 2012 draft IRP states: *"the short-term coal mining sales are expected to increase significantly due to expanded production from existing mines and the anticipated start-up of new mines in northeastern B.C. Global demand for metallurgical coal, particularly from China and India, is expected to be strong over this time period."*

*Figure 31: Western Coal's Wolverine mine processors and conveyor belts, near Tumbler Ridge*

*Figure 32: Teck's Quintette Coal Mine with a PH 4100 electric shovel which is slated to be used when the mine re-opens.*

**8. Total Potential Northern Industrial Load Growth**

These several northern industries are forecast to require a total of approximately 35,000 GWh/yr by 2026.

On the North Coast: 23,000 GWh/yr could be required for:

1. LNG Terminals
2. New and Expanding Mineral Mines
3. Port Expansions, and
4. Oil Pipelines and Refineries

In North East B.C., 12,000 GWh/yr could be required for:

1. Natural Gas Extraction, Processing, and Pipelining in;
   Montney, Horn River, and Liard/Cordova Shale Gas Basins
2. Synthetic Fuel Plants, and
3. New and Expanding Coal Mines

The total northern B.C. industry load growth forecast of 35,000 GWh/yr makes the following three conservative assumptions:

- It covers only 7 industrial sectors. For instance, it does not include sawmills, pulp and paper mills, lumber, manufacturing, quarries concrete production, agriculture, hot houses, or the chemical industry.

- It covers only northern B.C. The mines, pipelines, refineries, and ports located in the southern half of B.C. are not included.

- It covers only about one third of the projects that have been announced . That is, it assumes that two thirds of the announced projects will not get built.

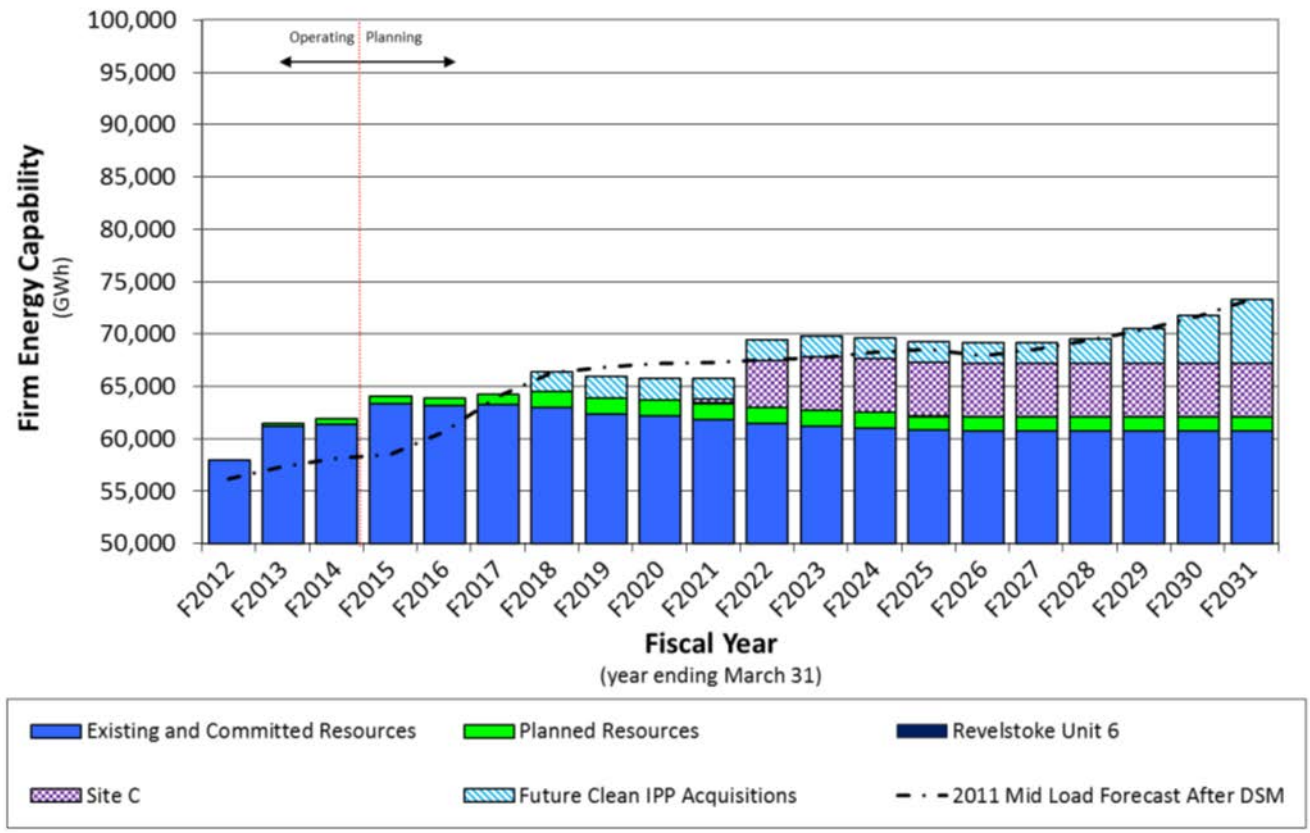
Potential load growth of 35,000 GWh/yr from these new northern industries would equal one and a half times the amount of BC Hydro's current entire industrial load.

## 9. BC Hydro draft 2012 IRP Base Resource Plan

The core of BC Hydro's 2012 Integrated Resource Plan, filed in May, 2012, is the Base Resource Plan (BRP).

The BRP is a 20-year view of various portfolios of resources needed to fill the energy supply gap. It is shown in the following graph.

*Figure 33: Base Resource Plan Energy Forecast - from BC Hydro draft 2012 IRP*



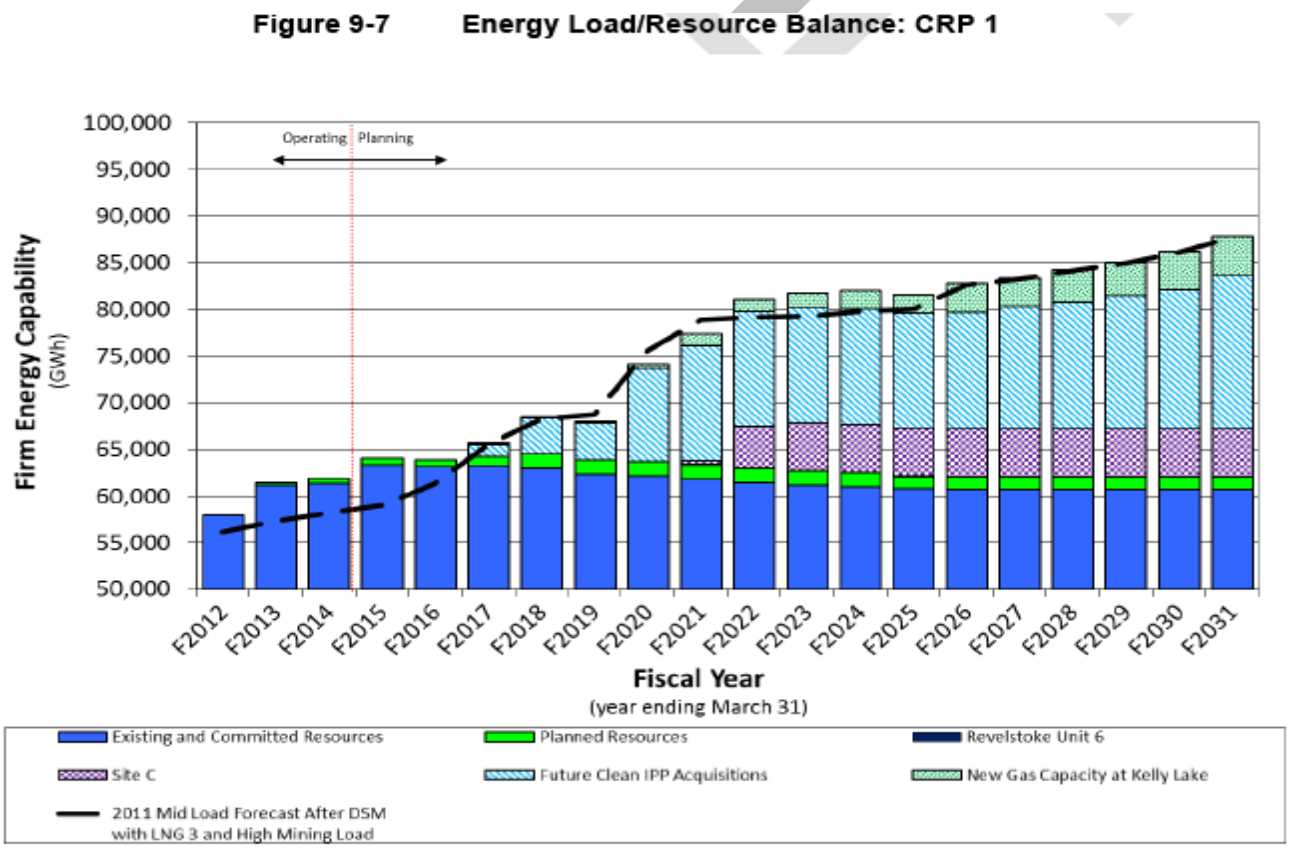

The BRP Energy Forecast Figure shows "Future Clean IPP Acquisitions" of approximately 2,000 GWh that would start to serve load in F2018.

BC Hydro also prepared a BRP without the Initial LNG using the same assumptions as the BRP with the Initial LNG. The BRP without the Initial LNG results in no need for "Future Clean IPP Acquisitions".

BC Hydro's contingency planning identifies alternative sources of supply that should be available should the BRP not materialize as expected. BC Hydro creates portfolios of resources called Contingence Resource Plans (CRPs).

The first of three CRPs is shown below.

*Figure 34: Energy Load/Resource Balance for Contingency Resource Plan 1- from BC Hydro draft 2012 IRP*




This Figure shows a potential increase of 25,000 GWh from 2012 to 2026. BC Hydro's draft 2012 IRP called this scenario Contingency Resource Plan 1 and stated that it mainly depend on future LNG expansion.

Since the draft IRP was issued there have been many announcements of LNG expansions, including; new LNG terminals advancements of the previously announced LNG terminals, .new gas pipelines and significant investment in North East gas basin activities.

## 10. BC Hydro Load Forecast in their 2013 Site C Environmental Impact Statement

In the Environmental Impact Statement (EIS) filed for their Site C project in February 2013, BC Hydro's load forecast states; *"The energy Load Resource Balance in Table 5.8 shows that … there is a need for energy beginning in F2024."*[10] The Table supports that statement by forecasting a surplus of energy in B.C. for the next 10 years, until 2023.

The table below shows that in 2026 BC Hydro will require new supply of between 1,000 and 7,300 GWh/year to be in load balance.

*Figure 35: Energy Forecast from Site C EIS filing under four scenarios*

| Energy Deficit (Surplus) in GWh | | | | |
|---|---|---|---|---|
| Year | No DSM or Rev 6 No LNG Load | With DSM & Rev 6 No LNG Load | With DSM, Rev 6, and Low LNG Load | With DSM, Rev 6, and High LNG Load |
| 2022 | 7,200 | (1,000) | (100) | 5,600 |
| 2026 | 10,000 | 1,000 | 1,600 | 7,300 |
| 2031 | 15,000 | 3,800 | 4,600 | 10,400 |

The "Low LNG Load" and "High LNG Load" covers only the "non-compression" load of the plant of 800 to 6,600 GWh/year. This appears to be ~15% of total plant load.

The following table shows Industrial load (without LNG) growing 1,800 GWh/yr from 2017 to 2026.[11]

*Figure 36: Mid-Energy Load Forecast (before DSM and losses) from Site C EIS filing*

[10] Page 5–4, Volume 1, Need for the Project, Site C Energy Project Environmental Impact Statement, February, 2013
[11] BC Hydro, Site C EIS, January, 2013

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**Table 5.3 Sector Breakdown of Mid-Energy Load Forecast Before DSM (Without Losses)**

| Energy Load (GWh/year) | F2017 | F2022 | F2026 | F2031 | Average Annual Growth Rate | |
|---|---|---|---|---|---|---|
| | | | | | F2012–22 | F2012–31 |
| Residential | 19,800 | 21,900 | 23,600 | 25,700 | 2.0% | 1.9% |
| Commercial | 17,800 | 20,100 | 21,300 | 23,000 | 2.5% | 2.1% |
| Industrial (without LNG) | 19,000 | 21,200 | 20,800 | 21,100 | 2.6% | 1.4% |
| Total domestic sales including sales to other utilities [a] (No LNG) | 57,600 | 64,500 | 67,200 | 71,400 | 2.4% | 1.8% |

# Northern hydro may be in the future for cleaner Alberta electricity

By Dave Cooper, Edmonton Journal May 9, 2013

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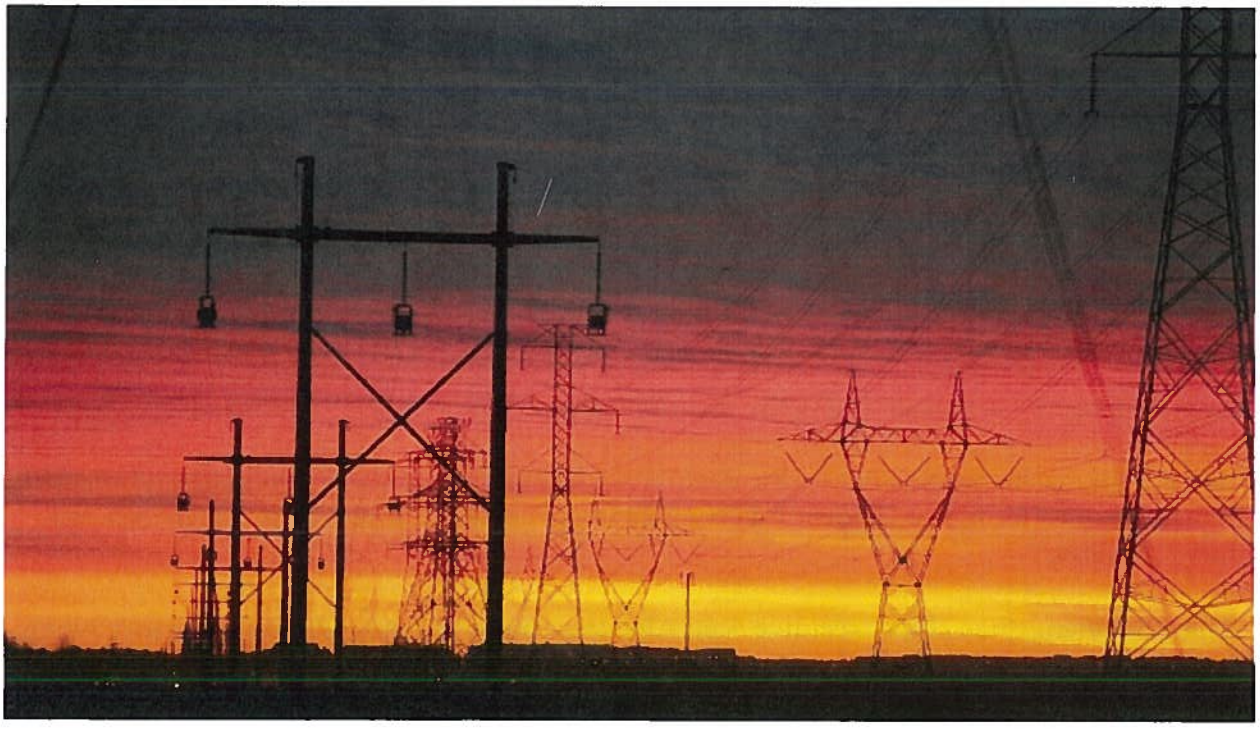

**Atco is setting its sights on the potential for northern hydro projects and new transmission lines to energize natural gas production in booming northwestern Alberta and British Columbia.**

**Photograph by: Bruce Edwards , Edmonton Journal**

EDMONTON - Atco is setting its sights on the potential for northern hydro projects and new transmission lines to energize natural gas production in booming northwestern Alberta and British Columbia.

"The Alberta government has taken an interest in looking at hydro as a replacement for coal-fired generation, and we have been continuing our talks with First Nations in the Northwest Territories. And the Taltson project is one they are supporting," said Siegfried Kiefer, chief operating officer for Atco's energy and utilities division.

The proposed Taltson dam project just north of the Alberta border is fairly small, able to generate 56 megawatts and situated adjacent to an existing 18 MW power plant built in the 1960s for a now-closed mine. The expansion is a joint venture with local aboriginal groups through Dezé Energy, and already has obtained all necessary permits to proceed. It would provide electricity for diamond mines north of Lesser Slave Lake that now rely on expensive diesel fuel, as well as add capacity for residential customers in the region, including Yellowknife.

For Atco, which faced strong opposition over its proposed Pelican Rapids site on the Slave River, the Taltson is a stepping stone to much larger future projects up the Mackenzie Valley. One site, Bear River, has similar potential to B.C.'s proposed 1,100 MW Site C dam on the Peace River.

"But you can't do Bear today. You have to work your way up, and Taltson could be a first step — the other sites will come on as it is economic to do it," said Kiefer.

However, the problem in the north is a lack of transmission lines. Atco would like to add a new line north from Fort McMurray to Fort Smith that would carry both Taltson power and the electricity from future dams south.

Dave Ramsay, NT's industry minister, said residents support Taltson.

"We are anxious to develop our hydro electricity potential, but we need to build the power grid in the territories for this to happen. And we believe we can work with Alberta to advance our mutual interest."

Nancy Southern, Atco chief executive, said Alberta's energy regulator should consider altering its long range plans for two new transmission lines to the Fort McMurray area, and send one to the Peace River region instead.

"We are seeing huge demand on the northeastern side of B.C., so I think we should be debating this," she said in an interview after the Canadian Utilities annual general meeting in Edmonton on Wednesday.

"Whether it is a 500Kv or 240Kv, a corridor needs to be built. We are talking with LNG (liquid natural gas) proponents and they have huge drilling programs to supply the LNG exports (at Prince Rupert and Kitimat). The drilling and natural gas upgrading and cleaning is very electricity intensive," she said.

Firms are now largely tied to using expensive diesel fuel and "and are looking for a longer term solution," she added.

Kiefer said the firms can't wait for electricity from B.C. Hydro's Site C dam.

"And the cost of power from that would be unacceptable to the people who need it."

But if B.C.'s dreams of becoming a major LNG exporting province are to be realized, a lot of Alberta natural gas will be going westward and prices will rise.

"Alberta produces about 10 billion cubic feet of natural gas per day, and each of those exporting terminals requires about two bcf. We are talking about doubling Alberta's gas production to feed that offtake," he added.

Higher natural gas prices will drive up power prices in Alberta.

"And this is why we feel Alberta shouldn't rush ahead and just build natural gas-fired power generation to fix their coal problem. It is best to have a portfolio approach," said Kiefer.

Atco has two large coal-fired plants at Battle River and Sheerness. It will be closing its oldest Battle River unit, which was built in 1969, by 2019 under the new federal rules for greenhouse gas emissions. However, other regulations still under discussion could force power firms to install additional pollution control equipment, which might force some plants to close before the 50 year cut-off.

Atco plans to add a new natural gas-fired turbine in the Industrial Heartland region, and recently purchased land near the Shell Scotford facility. The capacity and timing of that project are still under discussion.

dcooper@edmontonjournal.com