FOLLOW THE GA$:
KITIMAT LNG EXPORT TERMINAL AND PACIFIC TRAILS PIPELINE CHRONOLOGY

By Will Koop, revised, May 16, 2011 (original, April 19, 2011)
(*Stop Fracking British Columbia*: www.bctwa.org/FrackingBC.html)

Photo collage, with fracking operation and development top photos from northeast British Columbia's Horn River and lower Montney Basins. Third top photo from left is Encana Corporation's giant Cabin Gas processing plant project on a one square kilometre clearcut, a facility that will increase BC's annual greenhouse gas emissions. Background photo (by Daniel Wood) of Osler, Hoskin & Harcourt partner lawyers Tristram Mallett, Christopher Murray, Robert Desbarats, and Frank Turner (left to right) from the November 2010, monthly *American Lawyer* publication, the article by Julie Treidman called *Black Gold Rush*. The photo was taken at the G20 international summit held in Toronto on June 25, 2010 following "signing ceremonies related to 11 separate energy and natural resources investments by Chinese state-owned companies." The article continues to state: "Watching from the audience were lawyers from most of Canada's elite law firms, who had shepherded the deals to this point. "It was this giant blowing of kisses," says one of these lawyers. ... China National Petroleum Corporation (CNPC), China's largest oil and gas company, signed a memorandum of understanding with Encana Corporation, one of Canada's crown jewel natural gas companies, for a multibillion-dollar long-term investment in proposed shale gas projects in Western Canada. ... "These are the type of clients we want to work with," says Osler oil and gas partner Frank Turner. "They are an entree into the biggest deals in the world right now." " The month following the publication of this article, Apache Canada filed an application with the National Energy Board for a natural gas export licence for its proposed LNG terminal in Kitimat, and the attached Pacific Trails Pipeline proposal with partner EOG Resources, and the new Encana Corporation partner (with new PetroChina partner), which plan to export significant quantities of "dirty" gas largely from the Horn River Basin. The Osler law firm will be making a presentation, *Government Investment Support for Shale Gas*, at the April 27-29, 2011 Montney/Horn River Infrastructure Finance & Development Summit to be held in Calgary.

Website links to federal and provincial project information regarding the Kitimat LNG facility and Pacific Trail Pipeline project proposals

The details and documents for both project proposals can be found at the BC Environmental Assessment's and the federal Environmental Assessment Agency Office's websites:

BC EAO, Kitimat LNG Terminal:
http://a100.gov.bc.ca/appsdata/epic/html/deploy/epic_project_home_244.html

BC EAO, KSL Pipeline Looping Project:
http://a100.gov.bc.ca/appsdata/epic/html/deploy/epic_project_home_270.html

CEAA, Kitimat LNG Terminal:
http://www.ceaa.gc.ca/050/details-eng.cfm?evaluation=10430#Documents

CEAA, Northern Gateway Pipeline Project:
http://www.ceaa.gc.ca/050/details-eng.cfm?evaluation=21799

National Energy Board - KM LNG Operating General Partnership - December 2010 Application to export LNG:
http://www.neb-one.gc.ca/clf-nsi/rthnb/pplctnsbfrthnb/kmlnggh_1_2011/kmlnggh_1_2011-eng.html

National Energy Board KM LNG Documents:
https://www.neb-one.gc.ca/ll-eng/livelink.exe?func=ll&objId=657474&objAction=browse&sort=name&redirect=3

(Related information on the National Energy Board's Nova Horn River Mainline 36 inch diameter pipeline project hearing process regarding the export transmission of natural gas into Alberta from BC's Horn River Basin fracking fields:
https://www.neb-one.gc.ca/ll-eng/Livelink.exe?func=ll&objId=601085&objAction=browse&sort=-name

Intervenors

The following is a list of Intervenors in the National Energy Board's Kitimat LNG export hearing, currently scheduled for June 7, 2011 in Kitimat.

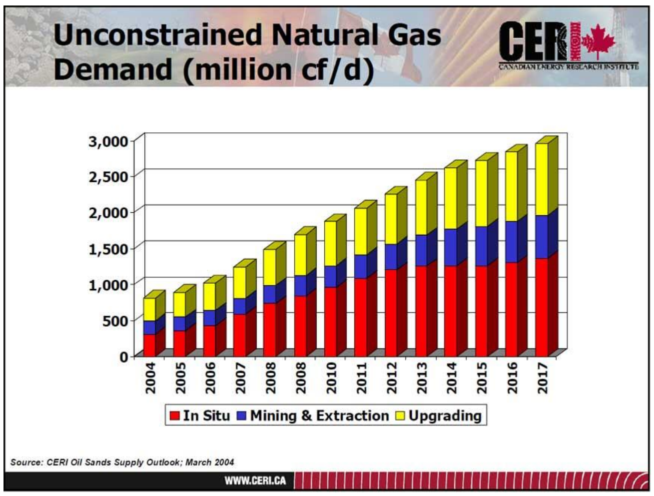
- Canadian **Association of Petroleum Producers** (CAPP)
- Dan Hall, **Chemistry Industry Association of Canada**
- **Export Users Group** (Avista Corporation, Cascade Natural Gas Corporation, Northwest Natural Gas Company, Puget Sound Energy, Inc.)
- Kitimat Rod and Gun Association
- Natalie Poole-Moffat, **Apache Canada Ltd.**

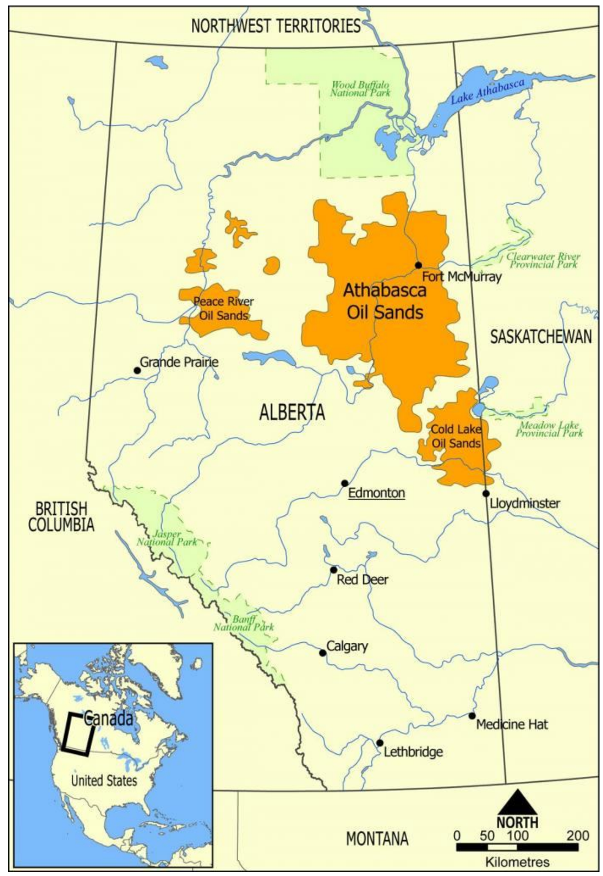
- Glenn W. Boone, **BP Canada Energy Company**
- Jim Gilholme, **ConocoPhillips Canada**
- Rinde Powell, **Encana Corporation**
- **EOG Resources Canada Inc.**
- Diane Roy, **Fortis BC**
- Thomas Tatham, **LNG Partners LLC** (and BC LNG Export Co-operative LLC)
- Debbie White, **Nexen Inc.**
- Garth Johnson, **Spectra Energy Transmission**
- Greg Giesbrecht, **Talisman Energy Inc.**
- Patrick M. Keys, **TransCanada Pipelines Limited**
- Gitxaala Nation
- Haisla First Nation (BC LNG Export Co-operative LLC, indirectly through HN DC LNG Limited Partnership)
- Peter King, Kitimat
- Joanne Monaghan, Mayor, District of Kitimat
- Dave Shannon, P.Eng., Terrace
- Colin King, Legal Counsel, **Alberta Department of Energy**
- Olga Klimko, Director, **BC Ministry of Energy**
- Charles Hansen, **Transport Canada**
- B.C. Tap Water Alliance
- Fort Nelson First Nation
- **Aitken Creek Gas Storage ULC**

SUMMARY

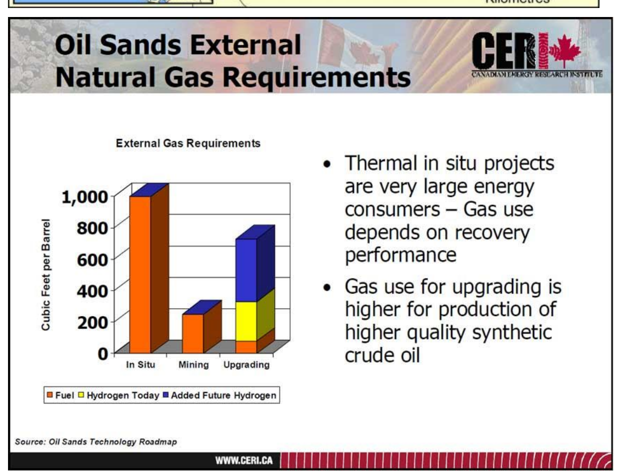
This chronology is meant to follow the B.C. Tap Water Alliance's interest and late Intervenor Status in the National Energy Board's hearing application for **Apache Canada**, **EOG Resources**, and **Encana Corporation's** export license for natural gas from a proposed LNG (Liquified Natural Gas) plant terminal near Kitimat, B.C., and the attending **Pacific Trails Pipeline (PTP)** project, alternatively referred to as the **Kitimat-Summit Lake Looping (KSL)** project by the BC Environmental Assessment Office.

There have been a number of LNG proposals from both Prince Rupert and Kitimat over the last thirty years, for both export and import rationales. None of the proposals were successful, until the ever-more present possibility of such slated for late 2011, at the brink of the "new age" of gas.





In 2004, former Duke Energy executives who formed a junior company called **Galveston LNG Inc.**, and its subsidiary **Kitimat LNG Inc.**, and who had understood the significant demand forecasts for natural gas by Alberta's tar sands operation companies, took the initiative and proposed an LNG import re-gasification facility near Kitimat. With the legal delaying impediments from the proposed Mackenzie Valley gas pipeline, Canada's natural gas reserves (including increased export shipments to the United States) were found wanting. In a January 2010 *Energy Risk* author analysis of natural gas use by Alberta's tar sands operations, by 2006 the tar sands had consumed a whopping 12 percent of Canada's total natural gas consumption!



Galveston LNG Inc. eventually struck a land use, business and equity deal with the Haisla First Nation to develop the LNG facility on its Reserve No. 6 at Bish Cove on Kitimat Arm. Galveston

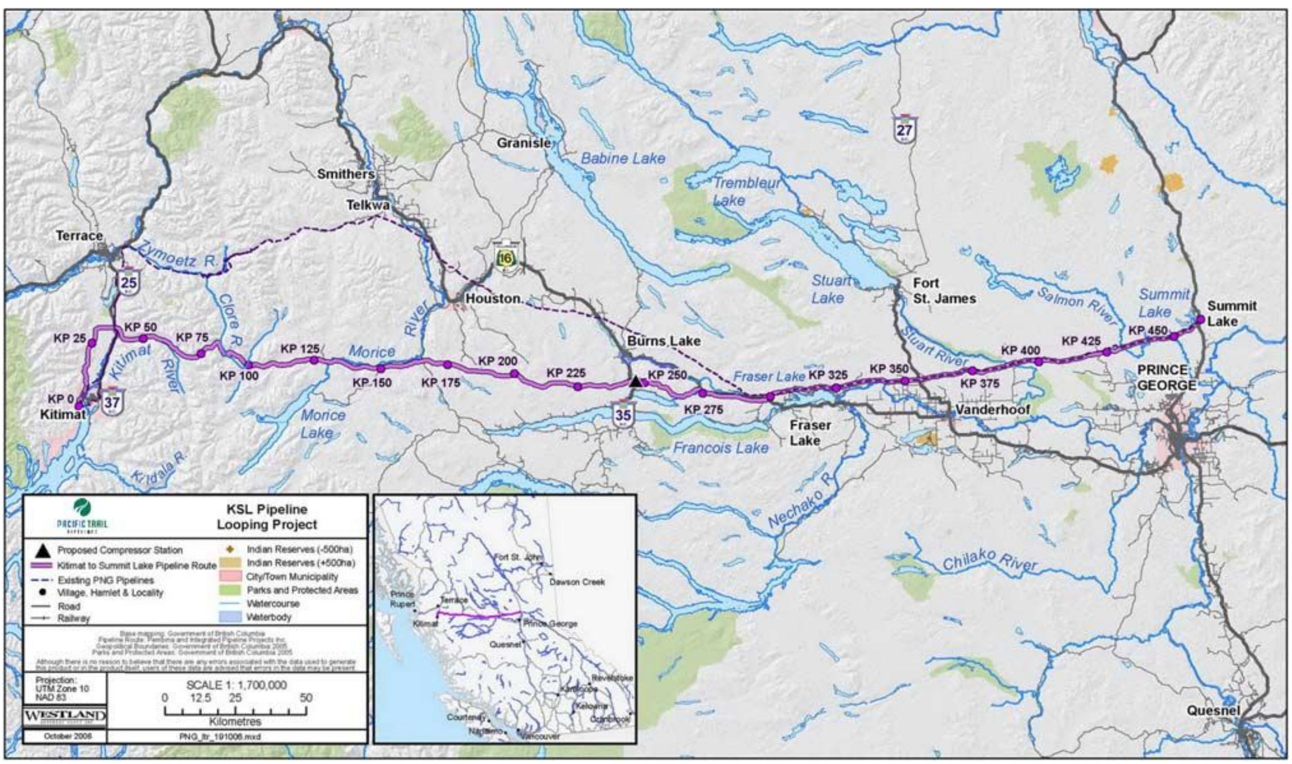
LNG Inc. obtained agreements for international LNG tanker shipments into Kitimat Arm primarily by Australia's **Liquified Natural Gas Ltd.** (It's about 7,000 miles (12,800 kilometres), or about 6,000 nautical miles in distance from Sydney Australia to Kitimat!)

Above, nine Kenworth trucks hauling and pushing a gigantic reactor to drive Suncor Energy's oil sands plant in northern Alberta. Below, photos of two (among a multitude of) tar sands development mammoth footprints.

Like the proposed MacKenzie Valley pipeline, to transport the large volume of natural gas from Kitimat to northeastern Alberta necessitates a new 36 inch diameter pipeline to be built across many First Nation lands, with an 18 metre wide right-of-way, over some 500 kilometres to **Duke Energy's** (renamed "**Spectra Energy**" in 2007) tie-in pipeline north of Prince George at Summit Lake. Based on a statement in a January 7, 2009 Environmental Assessment Office *Decision Note*, the estimated final delivery of gas in the new diameter pipe was at 700 million cubic feet per day (19.824 million cubic metres per day, or 7.236 billion cubic metres per year). In 2005, Pacific Northern Gas (PNG) initiated the pipeline proposal called the **Pacific Trails Pipeline (PTP)**, and later made a 50-50 partnership agreement with Galveston LNG Inc. The general location of the pipeline was the first phase of BC's new and controversial **Energy Corridor** discussions, other phases which included the Enbridge oil pipeline from Alberta's tar sands to Kitimat, which many First Nations strongly opposed in early 2011.

There is a fundamental question of whether delivery of oil sands product is better served by using existing infrastructure and footprints than by creating a whole new footprint with its own set of significant environmental impacts. We think this deserves a serious discussion and analysis, which currently does not exist in the application. (Source: Haisla Nation December 13, 2010 correspondence, *Additional Comments on Enbridges July 5, 2010 Procedural Direction*, CEAA document - Public Comments document list, Northern Gateway Pipeline Project.)

In relation, it is not known if First Nations had provided critical or ethical objections from 2005 onward regarding the LNG facility and its pipeline's purpose to directly support the dirty environmental footprint operations of Alberta's tar sands. Had they done so, their objections could have delayed or impaired the Kitimat LNG proposal. And, is it not known if First Nations were later cognisant of the multiple environmental footprint issues of where the new export gas from Kitimat was to be sourced from.

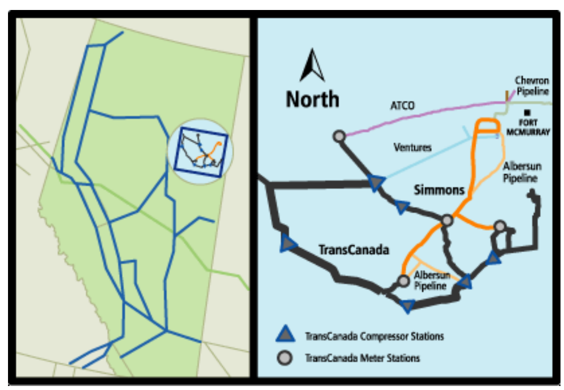


West of Fraser Lake, the proposed PTP deviates from paralleling the Pacific Northern Gas pipeline right-of-way, and proceeds through many wilderness and mountain landscapes, crosses numerous (589) stream and river courses. A deal was struck with 15 First Nations in 2009 for PTP partnership (the PNG and Galveston LNG Ltd. PTP partnership submitted an initial First Nations consultation report - the EAO called it “deep consultation” - to the BC Environmental Assessment Office on February 20, 2008, which included information on economic benefits to First Nations). Environmental and regulatory approvals were then granted by both provincial and federal agencies for both the Kitimat LNG facility and the PTP after both projects had gone through environmental and consultation review processes.

As the plans, approvals and agreements for the importation of natural gas to feed the tar sands proceeded, some of the same company players (and/or affliates) operating in Alberta’s tar sands also invested in northeastern BC’s deep shale gas zones by way of purchasing hundreds of petroleum leases on public lands from the BC government, agreements made without public consultation, without environmental and social cumulative effects requirements and stipulations. In 2005, **Apache Canada** and **Encana Corporation** began experimenting in the Horn River shales. By 2007 and 2008, gas energy captains more clearly realized from their new experimental drillings and production data that they apparently had a new confirmed, steady source of natural gas to feed the ever-hungry tar sands and speculated on yet another purpose for the Kitimat LNG. (In early February 2011, the Horn River players got final approval from the National Energy Board for Nova’s 36 inch diameter export pipeline into Alberta.)

According to **TransCanada Pipelines’s** website:

> The Simmons Pipeline delivers natural gas to the Fort McMurry oil sands area from several connecting receipt points on TransCanada’s Alberta System (NGTL), along with production connected directly to the pipeline.
>
> We see the Fort McMurray area as a strategic market. This transaction is important for our expansion plans into this attractive market and at the same time, allows us to defer capital expenditures, benefiting all Alberta System customers.
>
> “With the increased development of oil sands resources, growth in demand for natural gas is expected to continue in the Fort McMurray area,” says Don Bell, Sales Manager, Western End-Users and Interconnects.

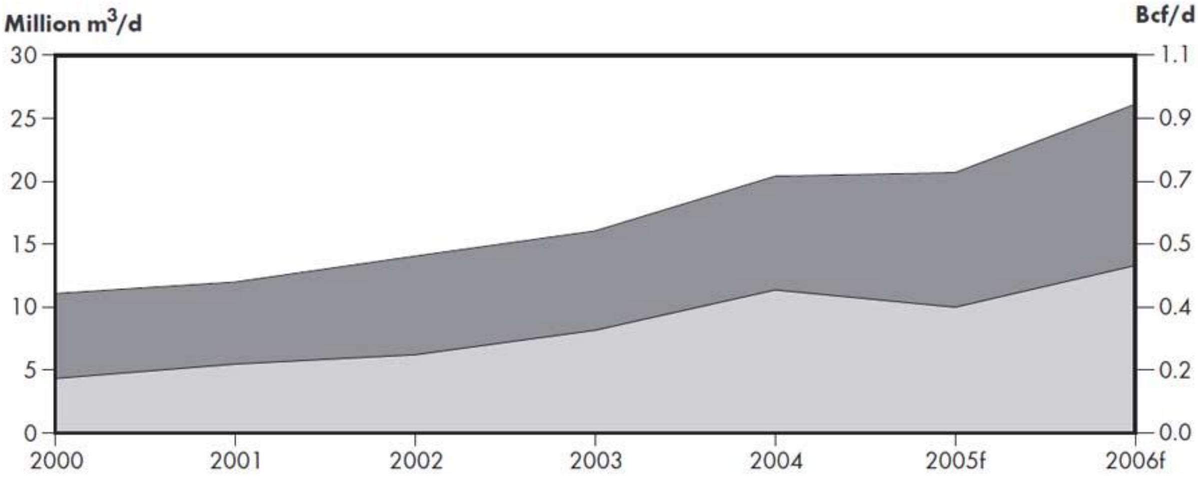


3.2.3 Natural Gas for Oil Sands

In 2004, about 20.4 million m^3/d (0.72 Bcf/d) of natural gas was used by oil sands projects to produce electricity onsite, provide process heat in bitumen recovery, and produce steam that is used for in situ recovery through steam injection processes. Natural gas is also an important source of hydrogen needed for hydro-cracking and hydro-treating in the upgrading of bitumen to higher quality synthetic crude oil.

FIGURE 3.8

Average Annual Natural Gas Requirements for Oil Sands Operations

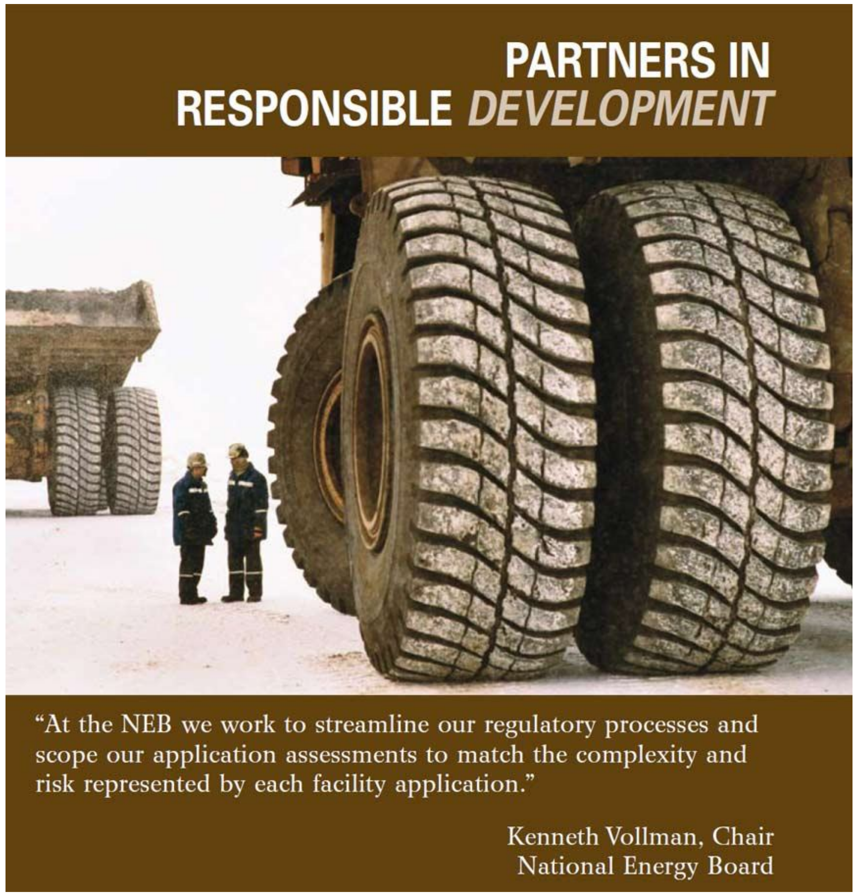


Note: f: forecast

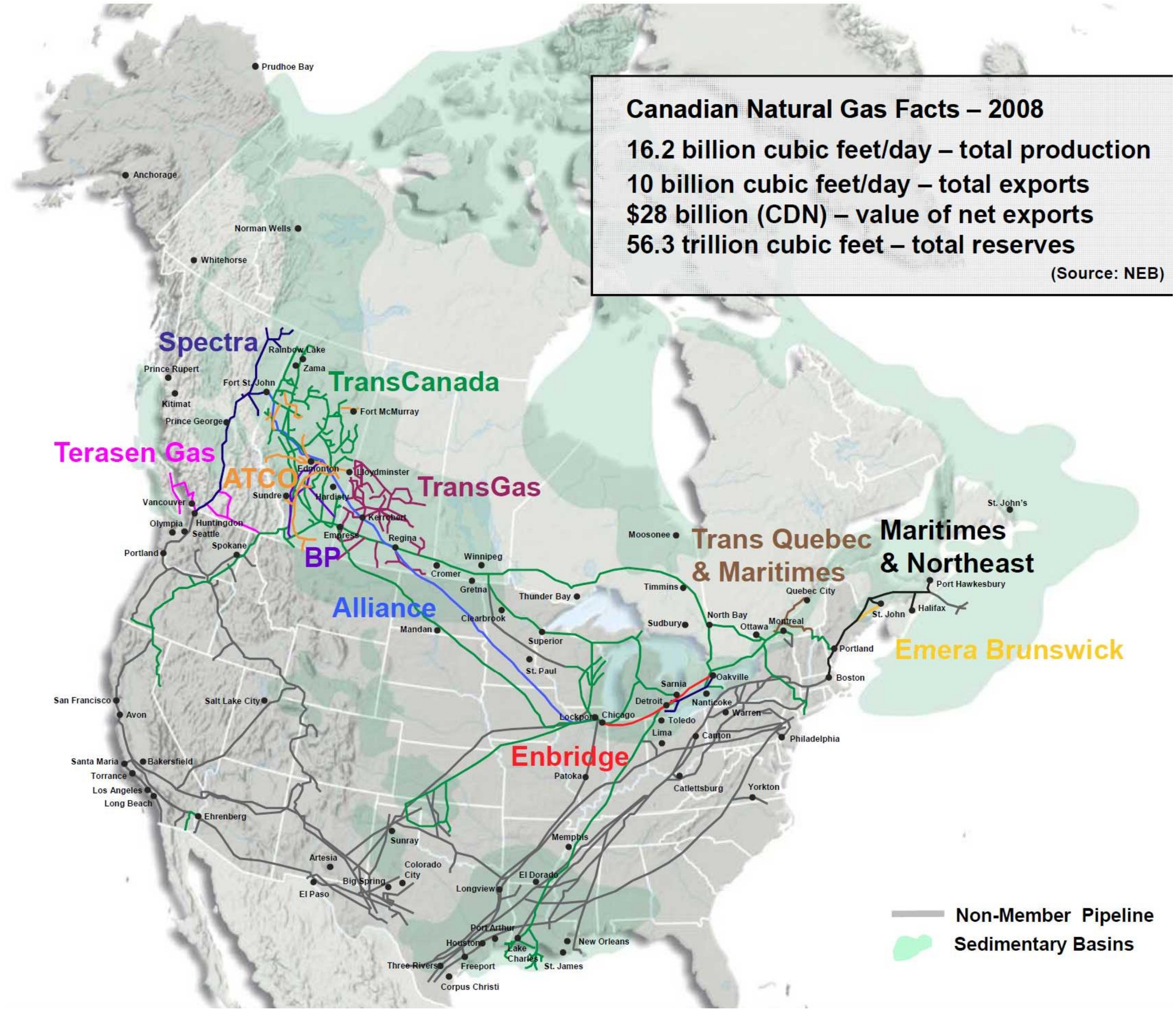
Source: EUB, NEB

With the scheduled start-up of Syncrude Canada Ltd.'s Stage 3 expansion and the addition of Suncor Energy Inc.'s Millennium Vacuum Unit, natural gas demand for mining and upgrading should grow to 13.6 million m^3/d (0.48 Bcf/d) by the end of 2006. The natural gas requirement for in situ projects is expected to increase during the outlook period to 15.2 million m^3/d (0.54 Bcf/d) as nine new projects or project expansions begin production (Figure 3.8). Hence, about 28.7 million m^3/d (1.01 Bcf/d) could be consumed at oil sands operations by the fourth quarter of 2006, averaging about 26.0 million m^3/d (0.92 Bcf/d) for the year. By 2006, total bitumen production will have almost doubled from 2000 levels, growing from 104.9 thousand m^3/day (660 Mb/d) in 2000 to 205.0 thousand m^3/d (1.29 MMb/d) in 2006.

Extracted from the National Energy Board's October 2005 report, *Short-term Outlook for Natural Gas and Natural Gas Liquids to 2006*.

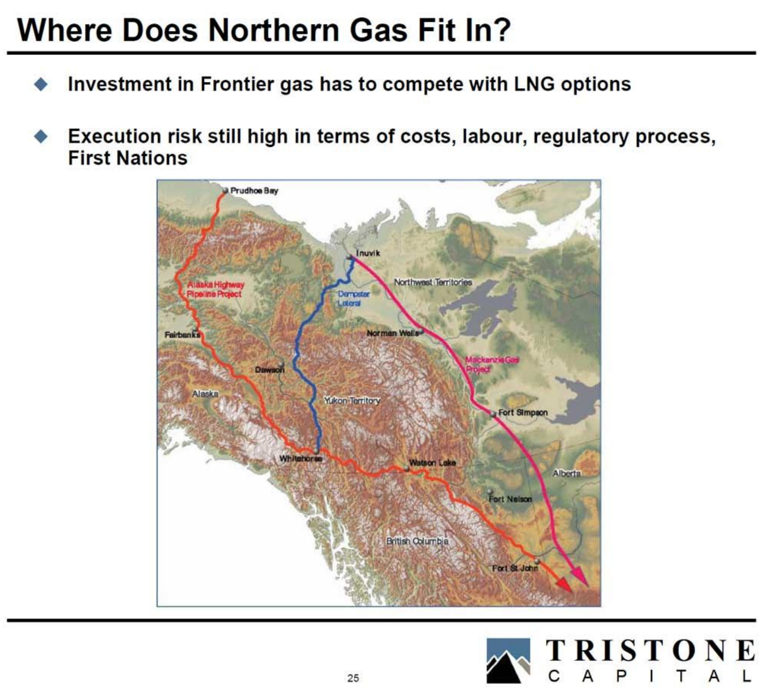


Framing the looming questions about environmental "sustainability" and "responsibility" regarding Alberta's odious tar sands. One of the main environmental planning weaknesses of both federal and provincial agencies is in conducting and providing long-term, integrated, meaningful, cumulative effects studies and conditions. (Photos and captions: segments from the National Energy Board's 2006 Annual Report)



Above: the ever-growing North American major natural gas pipeline network, 2008 (Terasen Gas, in pink color, is now owned by Fortis BC).

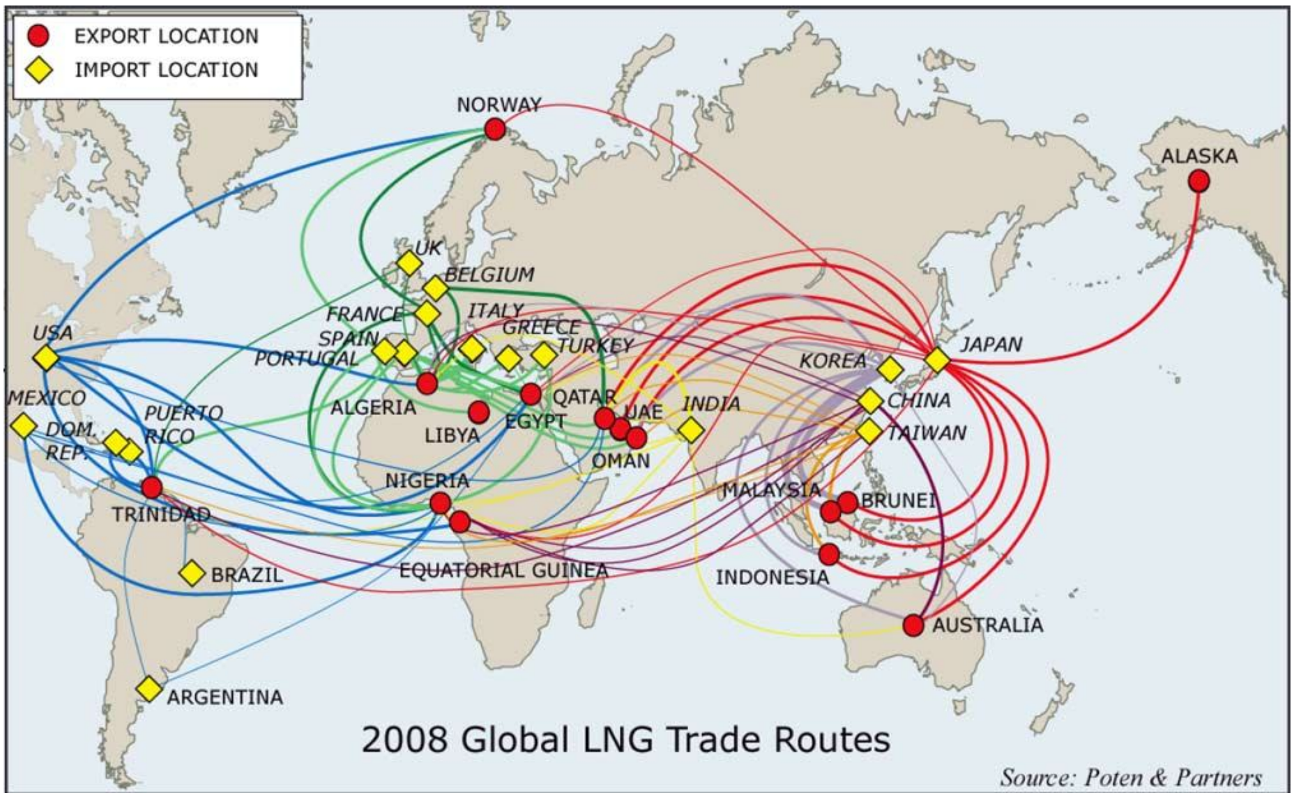
Right: 2004 future pipeline proposals from Alaska and Northwest Territories/Yukon.



THE SHIFT TOWARDS THE "NEW ERA FOR GAS"

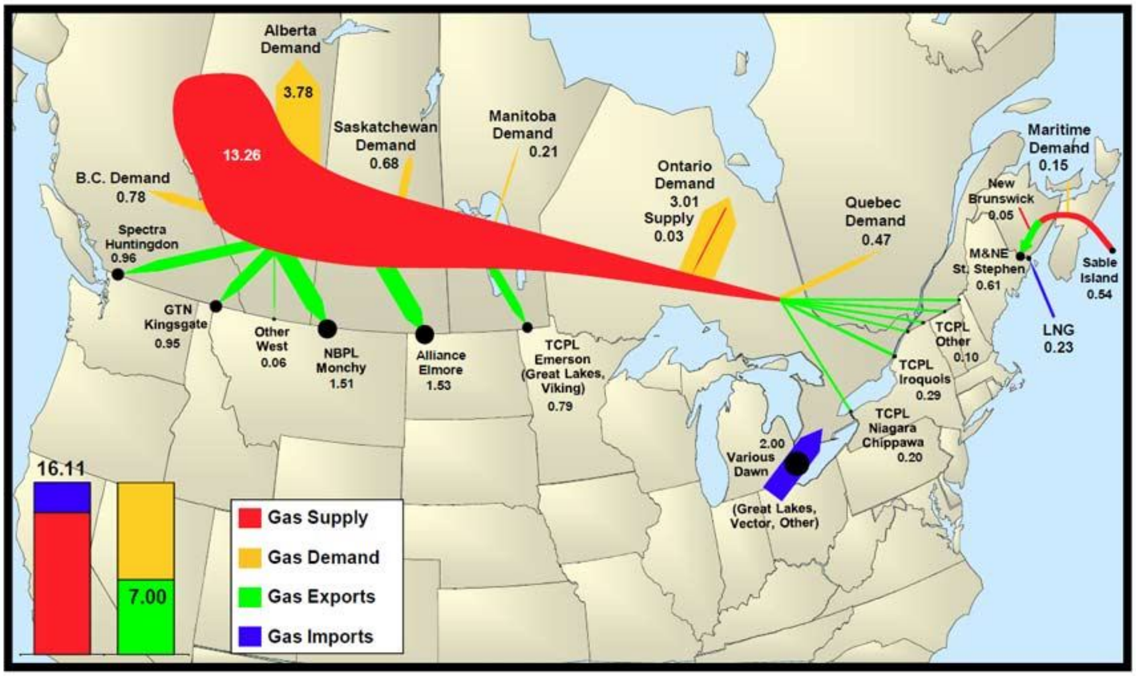
Seeing the new light, in late 2008 Galveston LNG Inc.'s Duke Energy executives announced that they had changed their source project objective: they now wanted to **export** natural gas out of Kitimat, and quickly received amendment approvals from both provincial and federal agencies. (Apparently, one of the Duke executives' intentions was for the pipeline to have an 'interchangeable' function: the pipeline could be used for both LNG import and export, the same alternate condition in Apache and EOG's updated application with the National Energy Board.)

Over a period of four years following 2004, industry forecasts for Canadian supply of natural gas reserves, such as those published by the National Energy Board, had suddenly and dramatically reversed. The deep shale natural gas gold rush in the United States (following the 2005 fracking exemption from the U.S. federal *Safe Drinking Water Act*, called the "Haliburton Loophole") had extended internationally, engulfing Canada almost overnight, and for the first time in the U.S. unconventional (deep shale) gas production rates in 2009 outstripped conventional gas rates.



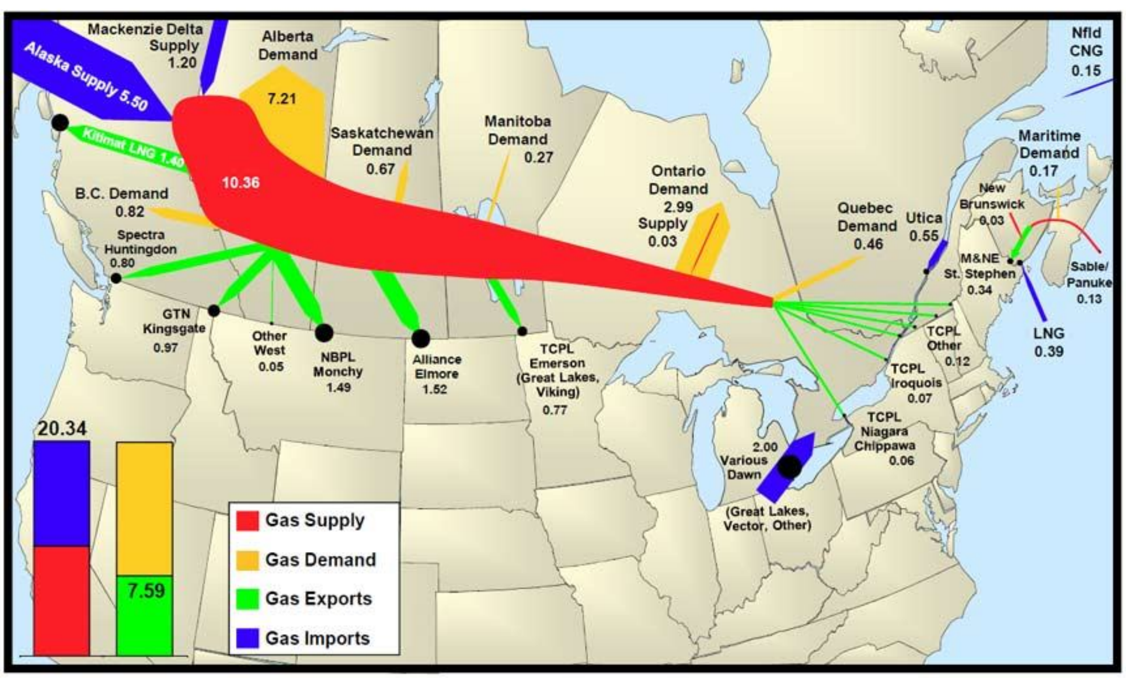
New Canadian gas reserve forecasts for 2010 and beyond were showing over-production rates well into the future. Northeast B.C. deep shale gas activities (referred to by the National Energy Board as "robust"), and those in Alberta, and perhaps those in Saskatchewan, would now provide natural gas to fuel Alberta's tar sands.

Canadian Gas Imports and Exports (Bcf/d), 2012



Images from Kitimat LNG's report application to the National Energy Board, *Natural Gas Demand and Supply Forecast*, North America and Canada (2010-2035), by Ziff Energy Group.

Canadian Gas Imports and Exports (Bcf/d), 2035



As now forecast by energy industry insiders, the projected over-production capacity of natural gas from B.C.'s public lands would have to be exported internationally, especially to overseas buyers willing to pay far higher or premium prices (almost triple rates) for gas, as lower Canadian and U.S. market prices were driving the fracking operations by energy companies in northeast B.C. into looming capital investment deficits.

> *The sizeable shale deposits located in North America have been discovered and developed at different rates, with US producers remaining firmly in the lead at present. While experts believe Canadian shale plays will eventually catch up, there are some disparities in costs that have fed into pricing, putting Canadian producers at a distinct disadvantage. As the US develops its domestic infrastructure and scales down its energy imports, Canada must look for new sources of demand as it pushes forward with its own shale plays.*
>
> *Canada has traditionally provided 90% of US natural gas imports, supplying 3.6 trillion cubic feet (tcf) of natural gas to the US in 2008 – 16% of US natural gas consumption. However, the US Energy Information Administration (EIA) calculates this could drop to 3% of total consumption in 2030. This will not be due to a lack of reserves on Canada's part, but rather the speed with which unconventional production can increase to replace declining conventional supply in Canada's Western Sedimentary Basin. Increased US production, mainly due to its own shale discoveries such as Marcellus and Barnett, will also play a part.*
>
> *For Canadian shale plays such as Horne River, several factors come into play to make gas produced here more expensive compared to US supplies. Horn River is in the north-eastern area of British Columbia. As yet it has little access to infrastructure such as roads or pipelines to encourage faster development. It is also located in a bogland, or muskeg, area where the marshy land makes development outside of the winter months impossible without costly specialist equipment.*
>
> *Peter Howard, who leads the natural gas research team at the Canadian Energy Research Institute (CERI), says: "The engineers and geologists at the Horne River Basin estimate the resource could potentially reach between 3 billion cubic feet (bcf) and 5 bcf per day, depending on market prices."*
>
> *According to Howard, Horne River projects would require a Henry Hub price of $6.50 or more to produce economically. The spot price at Henry Hub was $5.57/MMBtu at the time of going to press. "It's a remote area so the infrastructure isn't there yet in the form of gas lines, roads and equipment," he says. "Also, because it's in a muskeg area, drilling can only happen in the winter. Steps are being taken to get around that, such as the use of pad drilling, but a lot of money has to be spent building the pad to hold the weight of the equipment."*
>
> *When factoring in these extra expenses, the odds soon begin to stack up against Canadian plays. For example, Barclays Capital estimates that a horizontal well in the Horn River area currently costs between C$9 million (US$8.6 million) and C$12 million (US$11.4 million), compared to between US$7 million and US$10 million for similar wells in the Haynesville shale in Louisiana.*

> *Another area of concern for Canadian producers is the explosion of growth in the US shale plays themselves. As already discussed, they are much more developed than those in Canada and could begin to satisfy the bulk of US demand for natural gas as they reach their full potential. "At this point, potential production growth in the US is so strong that the need for imports from Canada will decrease going forward," says Pehlivanova.*
>
> *But experts are sure Canadian producers will find new markets. Domestic demand is likely to increase to fill at least part of the gap left by the US supply boost. CAPP forecasts oil sands production will grow from 1.2 million barrels per day in 2008 to about 3.3 million barrels per day in 2025. This growth will require a big increase in natural gas used in the production of oil sands. According to the EIA's International Energy Outlook 2009, 12% of Canada's total natural gas consumption was used for oil sands production in 2006. By 2030, it expects the share to reach 22% of the country's total gas use. Research by Ziff Energy Group estimates oil sands development would require almost 2 bcf per day of incremental gas by 2020.*
> (Source: *US Natural Gas Shale Plays Threaten Canada Export Market*, by Pauline McCallion, Energy Risk, January 13, 2010)

The *International Energy Outlook 2009* report by the Energy Information Administration footnotes on page 36 that improvements to "natural gas efficiency of oil sands production is assumed around 0.66 million cubic feet of purchased natural gas consumed per barrel of oil sands produced." It also states that Canada's total natural gas consumption in 2006 was 3.3 trillion cubic feet, which means that the tar sands alone used about 396 billion cubic feet (11.215 billion cubic metres) of gas for its operations in 2006, a figure projected to possibly increase to about 730 billion cubic feet (20.67 billion cubic metres) by 2020. In 2007, BC's total natural gas use for domestic, residential and commercial clients totalled 6.461 billion cubic meters, almost one half of what the tar sands used in 2006.

Galveston LNG Inc.'s new proposal for LNG export and initial memorandum agreements with **Mitsubishi Corporation**, **Korea Gas Corp.**, and Spain's **Gas Natural** drew attention by larger energy development corporation players **Apache Canada** and **EOG Resources** (both with headquarters in Houston, Texas), with agreements to supply PNG's and Galveston's Pacific Trails Pipeline. By January 2010, **Apache** gained 51 percent ownership of Galveston's subsidiary, Kitimat LNG Inc., and on the heels of **Apache's** ownership **EOG Resources** purchased Galveston LNG Inc. in May 2010, and obtained the remaining 49 percent interest in Kitimat LNG Inc. with Apache. Agreements were then made between the two Horn River deep shale basin players to take over the majority ownership of the Pacific Trails Pipeline, and an agreement with Pacific Northern Gas for it to provide maintenance of the pipeline after its construction for some 20 years.

In 2010, new international LNG purchasing agreements were being negotiated and arranged behind the scenes, particularly China's interest through its petroleum company **PetroChina** in LNG and its petroleum tenure land development partnership discussions with Encana Corporation. A number of international agreements were signed at the 2010, G-20 Toronto, Canada Summit meeting in late June, 2010 (see front page photo collage), where over 11,000 Canadian military forces, police officers and security guards were deployed to guard the proceedings against public protesters.

With all the new ducks lined up in a row, **Apache Canada**, by way of the **KM LNG Operating General Partnership**, filed for a two-phased, *Natural Gas Export Licence Application* with the

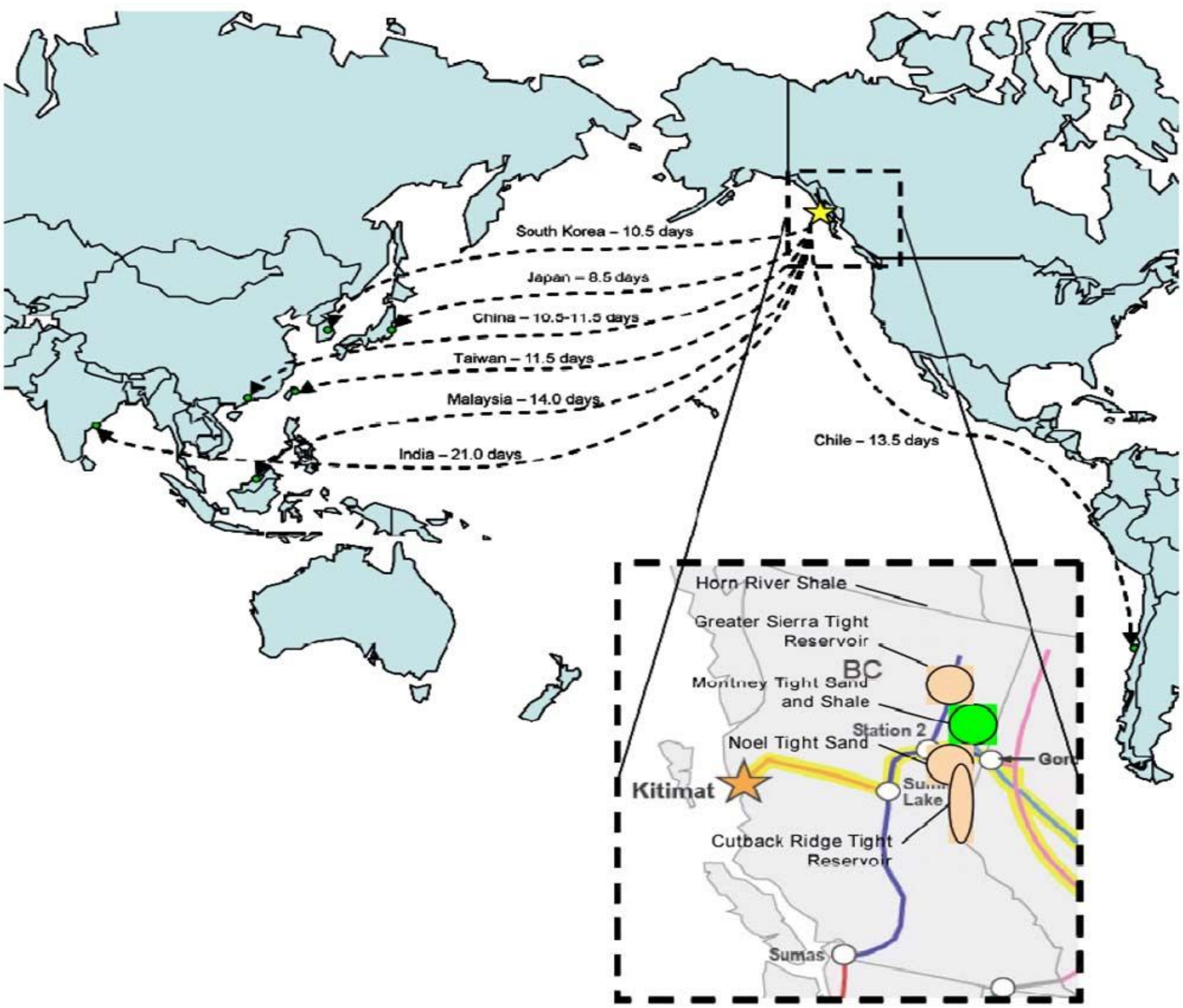
National Energy Board on December 9, 2010 (along with a number of documents), handled by its legal advisors with **Osler, Hoskin & Harcourt LLP**:

> ***This is the first time that an export of LNG has been applied-for under the present National Energy Board Part VI (Oil and Gas) Regulations, for the purpose of accessing offshore markets.*** *A daily maximum is not requested in light of the particular nature of this application.*
>
> *Unlike continental North American natural gas markets served by onshore pipelines, Asia Pacific LNG buyers are seeking long-term secure gas supply arrangements with regulatory certainty before committing to long-term contractual commitments. Therefore a long-term gas export licence is required prior to completing gas export sales contracts. This contrasts with the National Energy Board Part VI (Oil and Gas) Regulations requirement for gas export sales contract information as part of the gas export licence application.*
>
> ***The application is a response to a rapidly changing North American gas market that is driven by recent technological advances and a current and foreseen abundance of supply.*** *The majority of the gas that is proposed to be exported under the Licence will likely be sourced from Northeast British Columbia. This region is widely considered to hold significant gas resources, although it is in a relatively early stage of development.*
>
> *The significant investment required for the Kitimat LNG Terminal and PTP, noted above, and the opportunity to access new gas markets for Canadian natural gas production* ***at a price premium*** *[bold emphasis] will incent Terminal Owners to ensure sufficient gas supply is available so that the terminal may achieve high utilization rates. Terminal Owners have provided longterm financial commitments for the development of supporting infrastructure and will be strongly motivated to ensure that the capacity of all components of the project is highly utilized to secure appropriate returns on their investments.*
>
> *Apache's share of LNG to be exported under this Application will be sourced from its ownership of natural gas reserves and production located in Canada, currently British Columbia, Alberta and Saskatchewan, as it may evolve over the duration of the Licence ("Apache Corporate Supply Pool"). All gas reserves quoted by Apache and included in this Application are owned by Apache.*
>
> *EOG's share of LNG to be exported under this Application will be sourced from its ownership of natural gas reserves and production located in Canada, currently British Columbia and Alberta, as it may evolve over the duration of the Licence ("EOG Corporate Supply Pool"). At the present time, EOG is rationalizing its Alberta based reserves and the anticipated commercial transactions will impact this source of supply. Therefore, for the purposes of demonstrating that EOG has adequate reserves and supply to support the requested licence, EOG has focused on its British Columbia reserves. All gas reserves quoted by EOG and included in this application are owned by EOG.*
>
> *Terminal Owners will have the ability to purchase gas supply at Spectra's Station 2 if required. Station 2 is a liquid hub where gas from the entire Western Canadian Sedimentary Basin is accessible through swaps and potential future NOVA Inventory*

Transfers. Further, gas supply available at Spectra Station 2 is likely to increase significantly as Northeast British Columbia's Horn River and Montney Basins are developed.

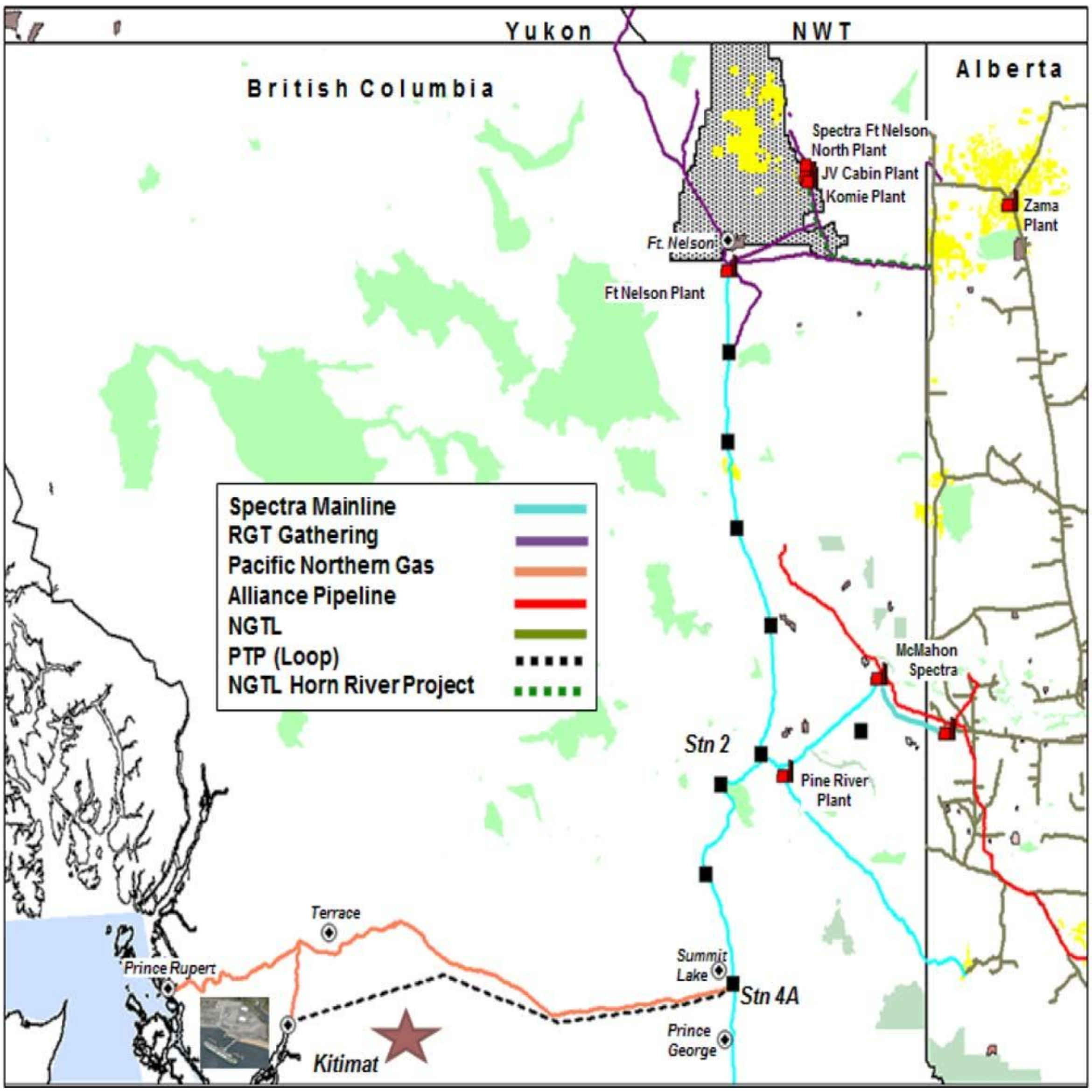
The potential environmental effects of the first phase of the Kitimat LNG Terminal and PTP have been evaluated by both federal and provincial environmental review processes. These processes concluded that neither project was likely to cause significant adverse environmental effects, provided that appropriate mitigation was applied and that the recommendations attached to the approvals were followed. These approvals are discussed further in Appendix 2 – Project Description and Status. In light of these circumstances, KM LNG does not consider there will be any additional environmental effects resulting from the issuance of the Licence.

Apache and EOG's application states that the two-phased LNG terminal is set to cost about $4.5 billion, and that the **Partnership** intends to export "up to 10 million tonnes" of LNG per year over a 20-year period, or about 13.2 billion cubic metres per year, almost double the initial import rate by Kitimat LNG Inc. stated a few years earlier. It's an astounding figure, representing about one half of BC's total annual net natural gas production in 2009!



Apache Canada's & EOG's December 2010 proposed LNG export scenarios from Kitimat.

In one of the **Partnership's** application documents by Roland Priddle, *Export Impact Assessment Report*, is the claim that 13.2 billion cubic metres, or 468 Bcf, per year will "not likely to cause Canadians difficulty in meeting their energy requirements at fair market prices." Aside from biased speculations about national economics, and the statement in the **Partnership's** report, *Natural Gas Demand and Supply Forecast*, that "Canadian gas demand growth is expected to be driven principally by ... increased gas requirements for growing Oil Sands production," **what about the more important question for British Columbians, namely the long term cumulative impacts to northeast BC's environment?** As stated in the **Partnership's** *2010-2035 LNG Market Assessment Outlook for the Kitimat LNG Terminal*, apparently the **Partnership**, and by way of extension all of the other corporate players in northeast BC, seems to be confident in something described as *"Canada's political stability and regulatory certainty."* The LNG plant is creating an addiction on what may correctly be called "dirty" gas, which is proceeding without environmental planning and public input. Recently, on April 13, 2011, the B.C. Tap Water Alliance, along with a small coalition of NGOs, petitioned the B.C. government to hold a public inquiry into the deep shale gas operations in northeast BC.



The 1.3 million hectare Horn River Basin is the shaded gray area, the yellow areas showing Apache's gas tenures.

In the Horn River Basin alone, located north and northeast of Fort Nelson, the **Partnership** reports that "approximately 230 wells have been drilled to date" by all the 27 different companies with hundreds of petroleum leases. In both Apache's and EOG's *Corporate Supply Pool* briefs to the National Energy Board, over a period of 24 years Apache intends to establish over 1,200 wells, and EOG over 1,300 wells. In addition, Apache has also alluded to building another gas processing facility south of Encana Corporation's Cabin Gas Plant and Spectra Energy's processing plant, another looming energy sucking and atmospheric emissions footprint.

About three months following the **Partnership's** December 2010 application for an LNG export licence with the National Energy Board, was the announcement that **Encana Corporation** had become **Apache** and **EOG's** new partner in **Kitimat LNG Inc.**, with a "30 percent working interest ownership", and partial ownership of the Pacific Trails Pipeline.

In late April, 2011, the Partnership provided revised information to the National Energy Board on its natural gas assets ("supply pools"), including new information from Encana (April 21, 2011, Alberta and British Columbia marketable gas volume estimates).

Table 3

Year	Wells per Year	Cumulative Well Count
2011	782	782
2012	1,312	2,093
2013	2,193	4,286
2014	1,541	5,827
2015	1,643	7,470
2016	1,539	9,009
2017	1,100	10,109
2018	1,074	11,182
2019	1,250	12,433
2020	1,266	13,699
2021	1,287	14,986
2022	1,248	16,234
2023	1,109	17,343
2024	1,145	18,488
2025	852	19,339
2026	709	20,048
2027	95	20,143
2028	0	20,143
2029	0	20,143
2030	0	20,143
2031	0	20,143
2032	0	20,143
2033	0	20,143
2034	0	20,143
2035	0	20,143

Encana's forecasted drilling schedule (April 21)

Figure 5 – EOG's Proposed Development Schedule

	Year	Total # Net Wells DRILLED	Cum # Wells
5 Year Plan	2010	10	10
	2011	10	20
	2012	9	29
	2013	75	104
	2014	75	179
5-10 Year Plan	2015	100	279
	2016	100	379
	2017	100	479
	2018	50	529
	2019	50	579
10+ Year Plan	2020	50	629
	2021	50	679
	2022	50	729
	2023	50	779
	2024	50	829
	2025	50	879
	2026	50	929
	2027	50	979
	2028	50	1,029
	2029	50	1,079
	2030	50	1,129
	2031	50	1,179
	2032	50	1,229
	2033	50	1,279
	2034	50	1,329
	2035	50	1,379
	2036	21	1,400

EOG's forecasted drilling schedule (April 26)

Revised Table 3

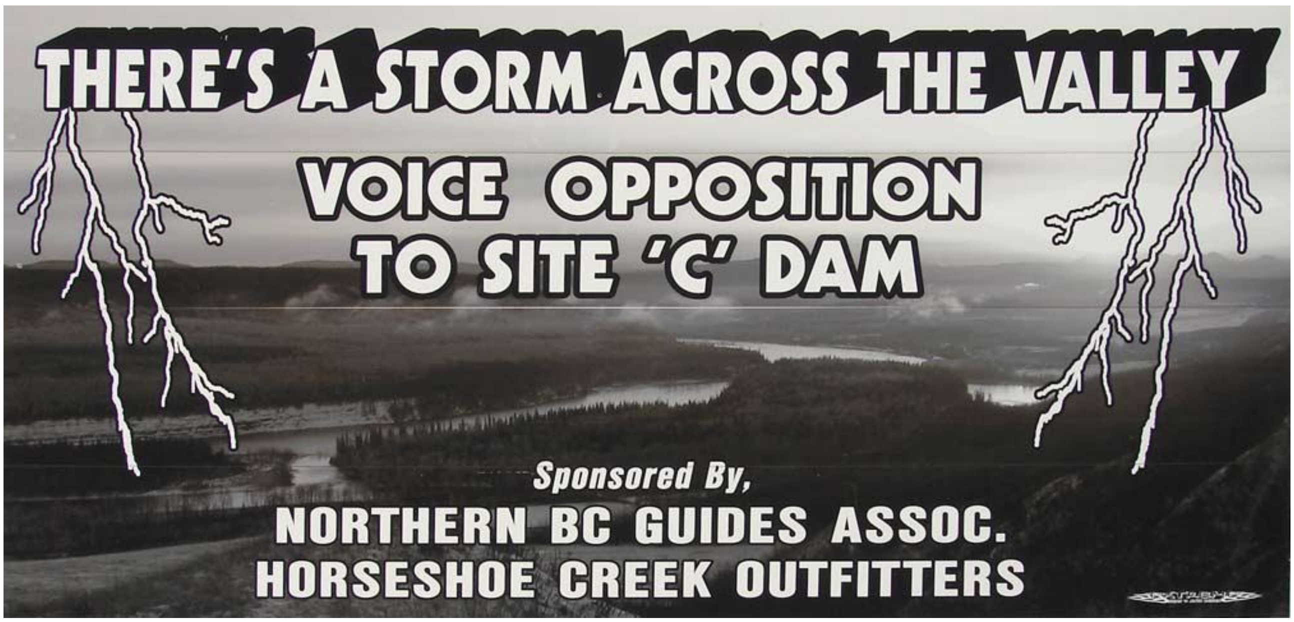
Year	Cumulative Net Average Producing Well Count	Apache Net Wells Drilled per Year
2011	32	3
2012	46	9
2013	64	14
2014	118	50
2015	160	42
2016	204	44
2017	249	45
2018	294	45
2019	340	46
2020	385	45
2021	430	45
2022	480	50
2023	525	46
2024	609	84
2025	697	88
2026	783	86
2027	843	61
2028	902	59
2029	960	58
2030	1018	58
2031	1076	58
2032	1134	58
2033	1183	48
2034	1183	0
2035	1183	0

Apache Canada's forecasted drilling schedule (March 15)

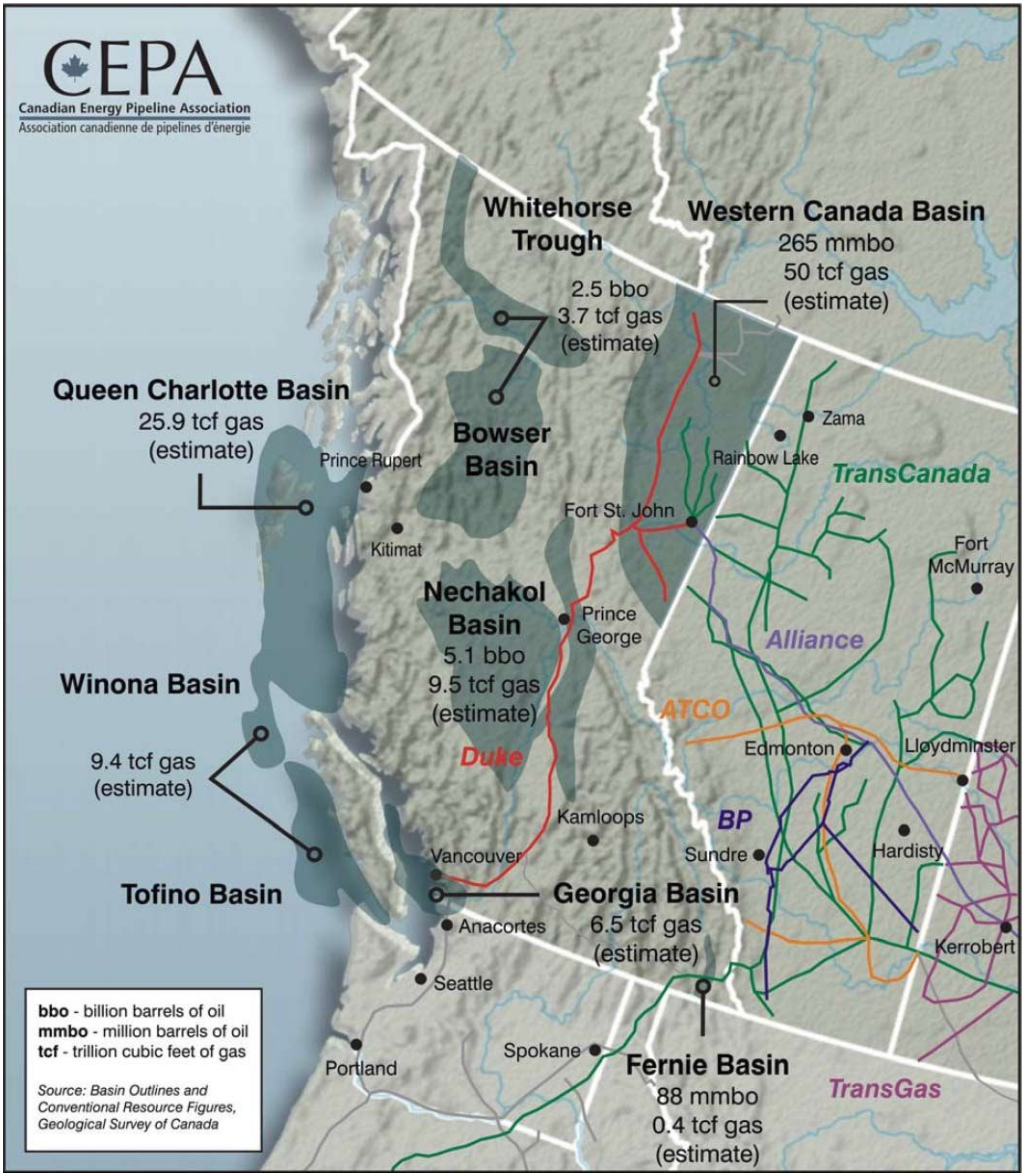
KITIMAT LNG TERMINAL	**APACHE**	**EOG RESOURCES**	**ENCANA**
Total Term Requirement at Inlet (assumes Phase 2 commences 2015)	20-year Term Requirement @ 40%	20-year Term Requirement @ 30%	20-year Term Requirement @ 30%
289.398 billion cubic metres (10,220 Bcf)	115.759 billion cubic metres (4,088 Bcf)	86.819 billion cubic metres (3,066 Bcf)	86.819 billion cubic metres (3,066 Bcf)
Total Daily Requirement at Inlet	@ 40%	@ 30%	@ 30%
Phase 1 (2015-2018) 19.8 million cubic metres/day (700 MMcf/d)	7.93 million cubic metres/day (280 MMcf/d)	5.95 million cubic metres/day (210 MMcf/d)	5.95 million cubic metres/day (210 MMcf/d)
Phase 2 (2018-2035) 39.6 million cubic metres/day (1,400 MMcf/d)	15.87 million cubic metres/day (560 MMcf/d)	11.89 million cubic metres/day (420 MMcf/d)	11.89 million cubic metres/day (420 MMcf/d)

With the current trends in northeast BC with larger international corporations, like China's **PetroChina**, and South African-based **Sasol**, taking on joint venture partnerships and perhaps even one day gaining more and more control over other companies, it is hard to predict who the future owners of the proposed Kitimat LNG terminal may be.

By 2010 and 2011, publications by national and international energy industry councils, associations and government agencies had pegged the future for natural gas, described by one as "the new era for gas". The new era arguments are found in: the World Energy Council's 2010 *Focus on Shale Gas* report; the World Economic Forum's *Energy Vision Update 2011, A New Era for Gas* report; and the recent April 2011 lengthy report by the U.S. Energy Information Administration, *World Shale Gas Resources: An Initial Assessment of 14 Regions Outside the United States*.



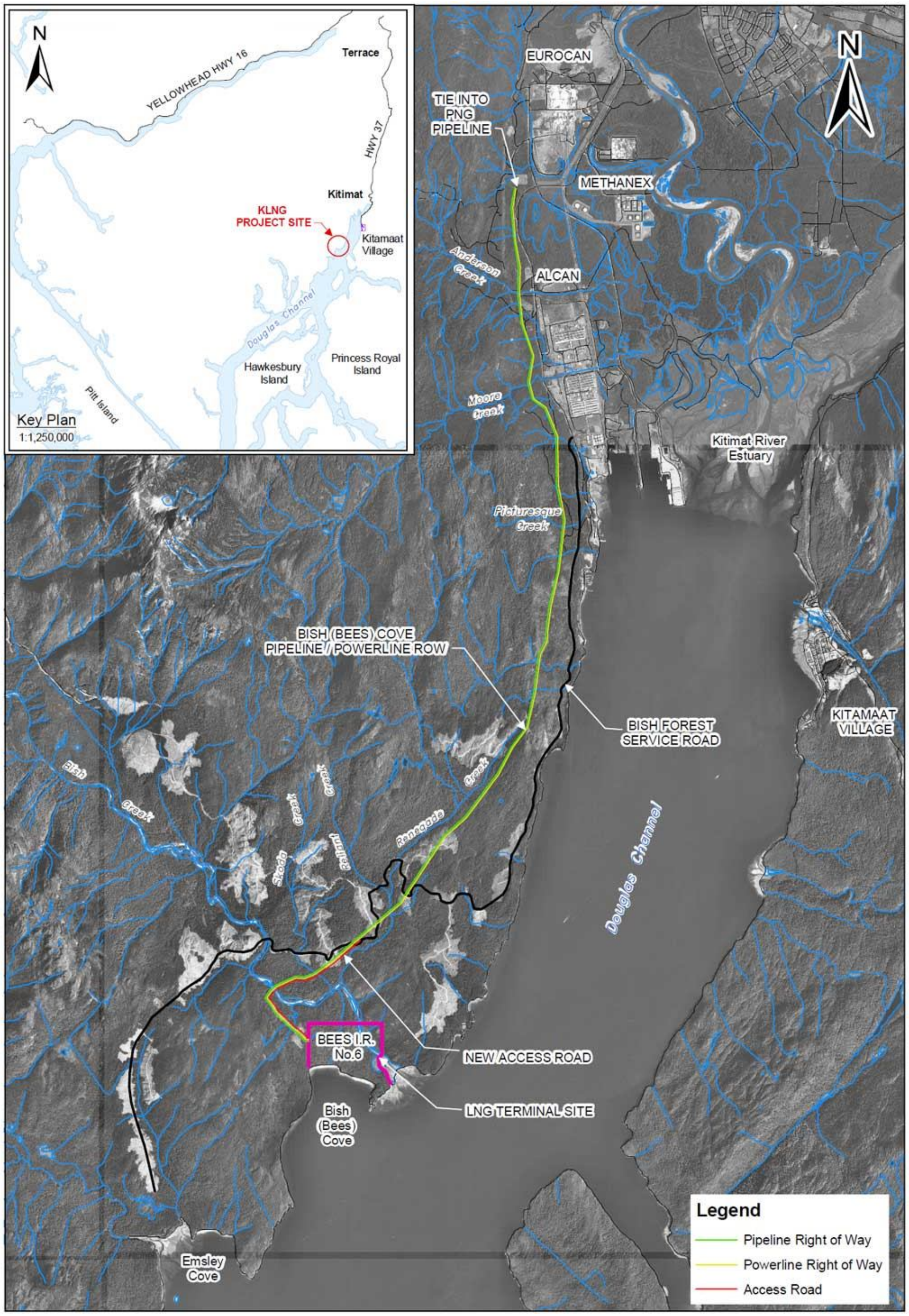
One of the possible future gigantic "footprints" of the shale gas developments in northeast B.C. is the proposal to build a third series of dams on the Peace River just west of Fort St. John, the controversial Site C dam, and a $300 million transmission line, to provide hydro electric energy to energy companies operating in the fracking basins. For instance, Encana Corporation's Cabin Lake new gas processing facility at full capacity would alone require almost the entire output of one of the six proposed turbines for Site C.



Currently, there are two primary active hydrocarbon development zones in B.C.: in the northeast Western Sedimentary Basin, defined by a 600 kilometre long energy zone (the length of one side of the triangle zone along the B.C. and Alberta border), where the Montney, Horn River, Liard, and Cordova Bay fracking zones are located; and developments in the Fernie Basin, in southwest B.C. In the future, all the other zones - the Georgia, Tofino, Winona, Nechako, Bowser, Queen Charlotte, and Whitehorse Trough Basins - will all be targeted for energy developments. In the future, all the energy corridor pipeline developments and environmental issues will be tied to these energy basins.

KITIMAT LNG EXPORT TERMINAL
AND PACIFIC TRAILS PIPELINE
CHRONOLOGY

He (Jim Wall, president of Apache Canada) *affirmed they were not like the Enbridge project that they had already received environmental approval.* (Source: Kitimat Daily Online, November 3, 2010)



1981

December 2 - The BC government sets a deadline for the Canadian petroleum industry to register proposals to dispose of the provincial gas surplus of 750 bcf (21.24 billion cubic metres). In response, the petroleum industry suggests 11 possibilities, three of which include LNG terminals. As reported in the Calgary Herald:

> The most ambitious single project comes from Vancouver entrepreneur **Bob Carter**, who is proposing to build a combined LNG-petrochemical facility at Ridley Island (Prince Rupert). This complex would ship an average 480 million cubic feet a day (MMcfd) of LNG to Japan and Korea over a 20-year period starting in 1987. In addition, a further 68 MMcfd of gas would be upgraded into petrochemicals.
>
> Two Japanese firms, **Sumitomo Corp.** and **Marubeni Corp.**, and a Korean company, **Daewoo Industrial Co.**, are planning to buy LNG from Carter, who puts the total cost of his project at $5.6 billion.
>
> This figure includes a $500 million drilling program with **Canadian Hunter Exploration Ltd.** in the B.C. Deep Basin.
>
> LNG proposals also come from **Dome Petroleum Ltd.** and from the **Rim Gas consortium** headed by the Crown corporation **Petro-Canada.** Surprisingly, however, no proposal was submitted by **Norcen Energy Resources Ltd.**, which had previously announced its own plans for an LNG plant.
>
> Dome and its partners - affiliate **TransCanada PipeLines Ltd.**; **Nova**, an Alberta Corp.; and the prospective LNG customer **NisshoIwai Corp.** of Japan - are planning a plant which would consume 170 bcf of gas a year. The total cost - including a shipyard and the construction of two LNG carriers - is put at $3.3 billion.
>
> The **Rim Gas** group - consisting of **Petro-Canada**, **Westcoast Transmission Ltd.** and **Mitsui and Co.** of Japan - is planning an LNG plant near Kitimat, which would consume just 115 bcf of gas a year. the cost is put at $2.3 billion, including construction of ships. This consortium has also committed to a $370 million drilling program in B.C. over the next 10 years.

1995

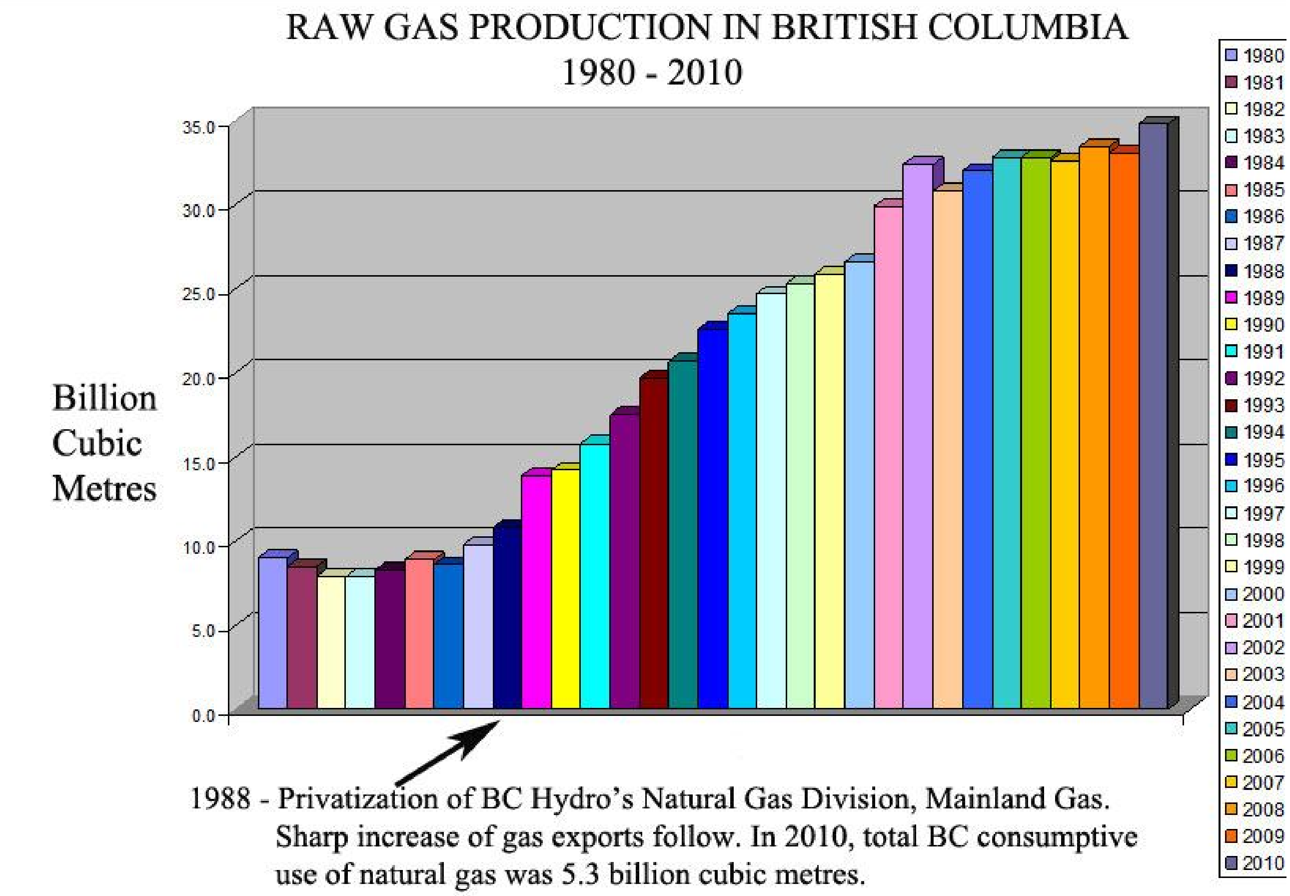
January - “Pac Rim LNG, a Calgary-based consortium of companies, has agreed to form a joint venture to promote and develop liquid natural gas facilities in British Columbia using natural gas from B.C. and Alberta.” (The Hamilton Spectator, January 30, 1995, *Venture Eyes Far East*)

1996

December - “An international joint venture company is planning a huge gas-liquefying plant near the Alaska border to export Canadian natural gas to Korea. The plant is to be built at the village of Kitimat, about 75 miles southeast of Prince Rupert. Cost of the project is estimated at more than $1.1 billion. The plant at the head of Douglas Channel would liquefy gas brought in a 24-inch pipeline from the Peace River area in northeast British Columbia.” (Anchorage Daily News, December 11, 1996, *LNG Plant Planned Near Prince Rupert*)

1997

April - "**Phillips Petroleum**, **Daewoo Corp.**, **Bechtel Enterprises** and **Pac-Rim LNG** have agreed to build $1 billion liquefied natural gas facility near Kitimat, B.C." (St. Paul Pioneer Press, April 10, 1997)



2002

March 14 - Following a public announcement in September 2001, the giant Delaware, Charlotte, North Carolina-based **Duke Energy Corporation** acquires **Westcoast Energy Inc.** with its Canadian holdings for (U.S.) $8 billion (the Canadian dollar was valued much lower than the U.S. dollar), including all ownership and distribution operations in British Columbia. In 2007, Westcoast Energy Inc. becomes a wholly owned subsidiary of **Spectra Energy Corp.**

> **Duke Energy Corporation** (collectively with its subsidiaries, Duke Energy), an integrated provider of energy and energy services, offers physical delivery and management of both electricity and natural gas throughout the U.S. and abroad. Duke Energy provides these and other services through the seven business segments described below.

Natural Gas Transmission provides transportation and storage of natural gas for customers throughout the East Coast and Southern U.S. and in Canada. Natural Gas Transmission also provides distribution service to retail customers in Ontario and Western Canada, and gas gathering and processing services to customers in Western Canada. Natural Gas Transmission does business primarily through Duke Energy Gas Transmission Corporation. Duke Energy acquired **Westcoast Energy Inc.** (Westcoast) on March 14, 2002 (see Note 2 to the Consolidated Financial Statements, "Business Acquisitions and Dispositions"). Duke Energy Gas Transmission's natural gas transmission and storage operations in the U.S. are subject to the FERC's and the Texas Railroad Commission's rules and regulations, while natural gas gathering, processing, transmission, distribution and storage operations in Canada are subject to the rules and regulations of the National Energy Board, the Ontario Energy Board and the British Columbia Utilities Commission.

Field Services gathers, compresses, treats, processes, transports, trades and markets, and stores natural gas; and produces, transports, trades and markets, and stores natural gas liquids (NGLs). It conducts operations primarily through **Duke Energy Field Services, LLC** (DEFS), which is approximately 30% owned by **ConocoPhillips** and approximately 70% owned by **Duke Energy**. Field Services gathers natural gas from production wellheads in Western Canada and 11 contiguous states in the U.S. Those systems serve major natural gas-producing regions in the Western Canadian Sedimentary Basin, Rocky Mountain, Permian Basin, Mid-Continent and East Texas-Austin Chalk-North Louisiana areas, as well as onshore and offshore Gulf Coast areas.

Duke Energy North America (DENA) develops, operates and manages merchant power generation facilities and engages in commodity sales and services related to natural gas and electric power. DENA conducts business throughout the U.S. and Canada through Duke Energy North America, LLC and **Duke Energy Trading and Marketing**, LLC (DETM). DETM is approximately 40% owned by ExxonMobil Corporation and approximately 60% owned by Duke Energy. Prior to April 1, 2002, the DENA business segment was combined with **Duke Energy Merchants Holdings**, LLC (DEM) to form a segment called **North American Wholesale Energy**. In 2002, management combined DEM with the Other Energy Services segment. Previous periods have been reclassified to conform to the current presentation.

International Energy develops, operates and manages natural gas transportation and power generation facilities, and engages in sales and marketing of natural gas and electric power outside the U.S. and Canada. It conducts operations primarily through **Duke Energy International, LLC** (DEI) and its activities target power generation in Latin America, power generation and natural gas transmission in Asia-Pacific and natural gas marketing in Northwest Europe.

2. Business Acquisitions and Dispositions

Acquisition of Westcoast Energy Inc. *(Westcoast)*. On March 14, 2002, Duke Energy acquired Westcoast for approximately $8 billion, including the assumption of $4.7 billion of debt. The assumed debt consists of debt of **Westcoast**, **Union Gas Limited** (Union Gas) (a wholly owned subsidiary of Westcoast) and various project entities that are wholly owned or consolidated by Duke Energy. The interest rates on the assumed debt range from 1.8% to 15.0%, with maturity dates ranging from 2002 through 2031. Westcoast, headquartered in

Vancouver, British Columbia, is a North American energy company with interests in natural gas gathering, processing, transmission, storage and distribution, as well as power generation and international energy businesses.

In the transaction, a Duke Energy subsidiary acquired all of the outstanding common shares of Westcoast in exchange for approximately $1.7 billion in cash (net of cash acquired) and approximately 49.9 million shares of Duke Energy common stock (including exchangeable shares of a Duke Energy Canadian subsidiary that are substantially equivalent to and exchangeable on a onefor-one basis for Duke Energy common stock). The value of the Duke Energy common stock issued was approximately $1.7 billion and was determined based on the average market price of Duke Energy's common shares over the two-day period before and after the terms of the transaction became fixed, in accordance with EITF No. 99-12, "Determination of the Measurement Date for the Market Price of Acquirer Securities Issued in a Purchase Business Combination." Under prorating provisions of the acquisition agreement that ensured that approximately 50% of the total consideration was paid in cash and 50% in stock, each common share of Westcoast entitled the holder to elect to receive 43.80 in Canadian dollars, or either 0.7711 of a share of Duke Energy common stock or of an exchangeable share of a Duke Energy Canadian subsidiary, or a combination thereof. The cash portion of the consideration was funded with the proceeds from the issuance of $750 million in mandatory convertible securities (Equity Units) in November 2001 (see Note 18) along with incremental commercial paper. The commercial paper was repaid using the proceeds from the October 2002 public offering of Duke Energy Common Stock (see Note 18).

The acquisition of Westcoast was consistent with Duke Energy's natural gas pipeline strategy to expand its footprint between key supply and market areas in North America. During its evaluation, Duke Energy identified revenue enhancement opportunities through expansion projects and business integration, cost reduction initiatives, and the divestiture of several non-strategic business lines and assets. These initiatives, when combined with the ongoing earnings contributions from Westcoast's pipelines and distribution businesses, supported a purchase price in excess of the fair value of Westcoast's assets, which resulted in the recognition of goodwill. The Westcoast acquisition was accounted for using the purchase method, and goodwill of approximately $2.3 billion was recorded in the transaction, of which approximately $57 million is expected to be deductible for income tax purposes. Of this amount, $52 million was allocated for tax purposes to Empire State Pipeline which was sold in February 2003 (see Note 22).

(Source: Duke Energy Corporation 2002 Annual Report - U.S. Securities and Exchange Commission, Form 10-K)

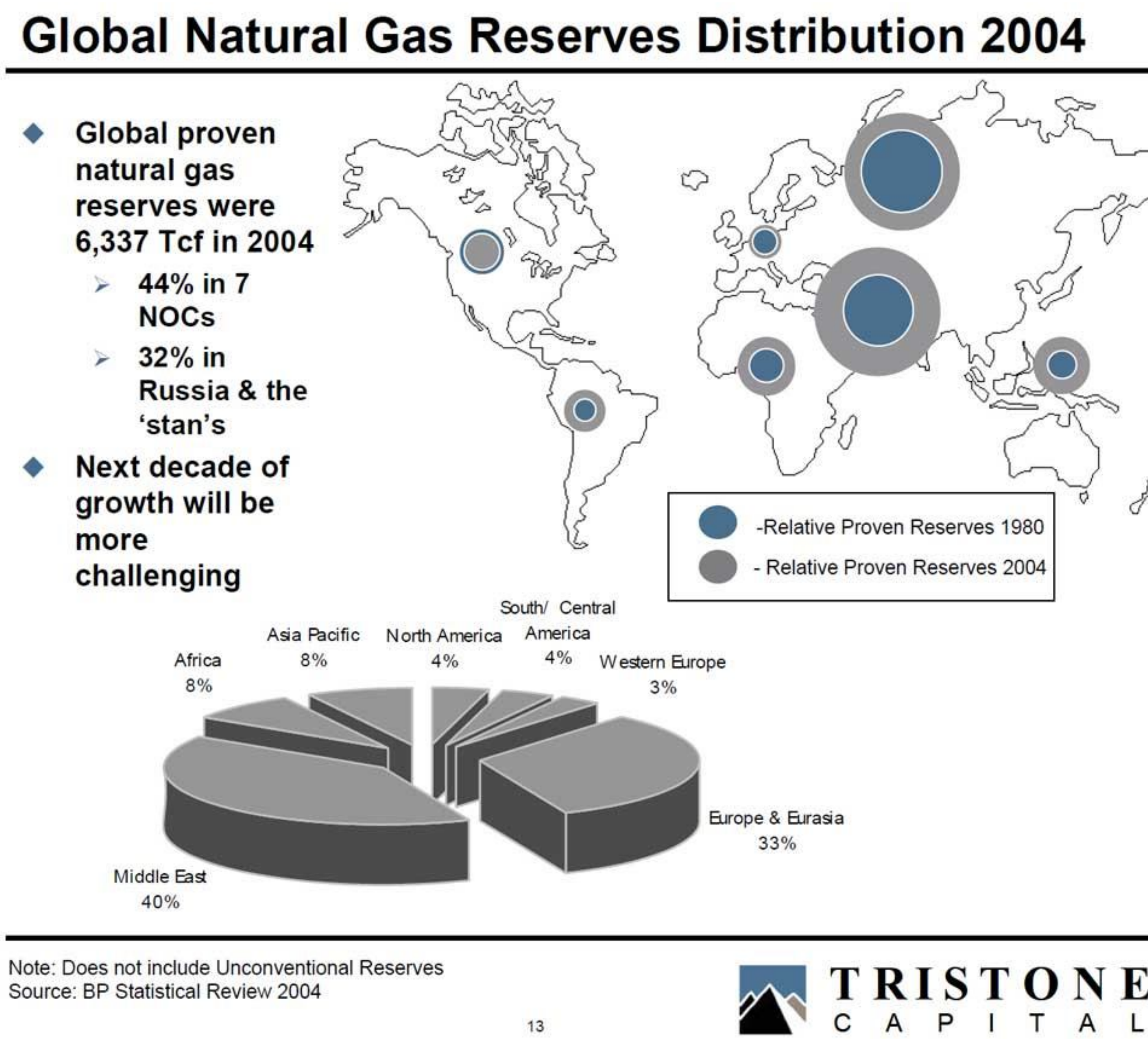
In Duke Energy-owned Westcoast Energy Inc.'s 2001 annual report, the company had a new vision for natural gas use in North America:

MARKET OUTLOOK

Notwithstanding the dramatic swings in natural gas pricing over the past two years, long-term forecasts continue to predict a North American natural gas market of approximately 30 trillion cubic feet per annum by 2015. Continued growth in infrastructure will be required to supply this market.

The largest contributor to the current growth in natural gas demand remains the generation of electric power. The long-term view is for growth in demand for electricity to continue, necessitating construction of additional generating capacity to meet the incremental demand. Natural gas fired generation of electricity is expected to be a significant source of incremental power supply.

Increasingly, natural gas supply from Canada will be required to meet increases in demand for natural gas in North America. Some of the key incremental supply regions in Canada include the offshore region of Nova Scotia, northeast British Columbia and the southern Northwest Territories. The Company is well positioned in each of these producing regions with pipeline systems that connect these regions with attractive and growing natural gas markets.



2004

January 19 - **Galveston LNG Inc.** becomes incorporated as a private Canadian energy company (corporate number, 2010866727), with its office in Calgary, Alberta. **Galveston Inc.** was founded by **Alfred Sorensen**, a former executive with Charlotte, North Carolina-based **Duke Energy**. The following biography on Sorensen from Bloomberg:

> Alfred Sorensen, B. Comm, C.A. serves as the Head of DEI Europe and Senior Vice President of DEI of **Duke Energy International**, LLC. Mr. Sorensen serves as the President and Chief Executive Officer of **Galveston LNG Inc.** He serves as the Chief Executive Officer of **Kitimat LNG Inc.** at **Galveston LNG Inc.** He was the president of the Canadian trading division of Duke **Energy Trading and Marketing** (DETM), since 1997. He began his career at **Duke Energy** in 1987 as a marketing representative. Since then he has served in a number of positions of increasing responsibility within the trading company and since 1999 was responsible for expanding DETM's Canadian division into power trading from its gas trading platform. He was the President of **Duke Energy (Europe) Ltd.** and was responsible for the development of Duke Energy's European strategy. He also established a full-scale energy-trading unit. He joined SGP with a wealth of experience in the energy sector. He served as a Partner of **Continental Energy Marketing Ltd.** He has been an Independent Director of **Sierra Geothermal Power Corp.** since March 12, 2008. He serves as a Director of **Galveston LNG Inc.** Mr. Sorensen is a Chartered Accountant and holds a Bachelor of Commerce Degree from the University of Alberta.

An August 2007 article in Oilweek Magazine by Andrea Lorenz provided scant background information on **Galveston Inc.'s** "small group of entrepreneurs, four of whom knew each other from their days as **Duke Energy** marketers:"

> *After studying the area carefully, **Galveston's** team of chief executive officer Alfred Sorensen, co-founder Thom Dawson (now LNG Impel president), vice-president of risk management Dale Dixon, and KLNG president, Rosemary Boulton pinpointed the spot where they wanted to build the terminal.*
>
> *In the late 1990s, they decided to hitch their company to the LNG star and to begin looking for a terminal location. ... By the time **Galveston's** executive team began their search, communities up and down both coasts of the United States and Canada had rejected enticing proposals from the mightiest multinational corporations. Competition for the right site was so fierce that **Galveston's** founders—who had had their sights set on Kitimat from the beginning—threw their competitors off the scent by naming their first company after the Texas coast city whose residents were being wooed by several companies.*
>
> *The KLNG/Haisla deal is emblematic of the realization by Canada's aboriginal leaders that they now wield unprecedented leverage over the fate of projects like the Mackenzie Gas Project, the Gateway Pipeline, and a raft of others competing for their approval.*

Aboriginal bands can provide investors and planners with what they want most aside from profits—certainty—or they can hold projects hostage. They can demonstrate their support to the government, thereby fast-tracking the regulatory process, or they can oppose and obfuscate, eventually frustrating impatient foreign investors into withdrawing their support.

When they approached the Haisla, Chief Steve Wilson and his team told them that while his band members were supportive of the project, they preferred that the terminal be built at a different site called Bish Cove.

Councillor Keith Nyce, one of the band's chief negotiators, escorted Oilweek's photographer and associate editor by powerboat to see both sites.

When it came to arguing their case, the Haisla had a significant advantage: two companies had previously conducted engineering studies of the Bish Cove site for an LNG terminal and had concluded that it was satisfactory.

They also knew that the Galveston team was in a hurry to scoop their competitors. KLNG's Boulton and her team were eager to fast-track the environmental review, to begin courting suppliers, and to secure so-called "first-mover" advantage. If the Haisla refused to support the project, it could be mired in delays.

April - Kitimat LNG begins conducting environmental field studies and negotiations with the BC government, the Haisla Nation and the District of Kitimat regarding its proposed import LNG terminal near Kitimat for a regasification facility.

> The proponent of the proposed LNG facility in Kitimat, Kitimat LNG Terminal ("Kitimat LNG"), has commenced the process to obtain a Project Approval Certificate from the British Columbia Environmental Assessment Office and Canadian Environmental Assessment Agency. This certificate would allow construction and operation of its project, which is proposed initially to accommodate imports of up to 610 MMcf/day of natural gas commencing in late 2008. Kitimat LNG has indicated its desire to utilize the Company's natural gas transportation services to deliver the regasified LNG into the **Duke Energy Gas Transmission** system at the point of the existing interconnection with the Company. The Company would be required to reverse the flow of its pipeline and expand its capacity in the event the Kitimat LNG project proceeds as planned.
>
> In the Company's Northeast region there has been recent growth in the oil and gas sector, as well as the coal sector, which may expand the Company's customer base in that region. (PNG Annual Information Form, 2004)

June - Premier Gordon Campbell writes a letter of support for the LNG import proposal in Kitimat. Following the majority BC Liberal government election in May, 2001, winning an unprecedented 77 out of 79 seats, and following the initiation of the Red Tap Task Force (2001-2002), the government begins slashing environmental legislations and regulations, including the provincial Environmental Assessment Act. The Act, passed into legislation under the New Democrats in 1995, was BC's first critical planning tool for large-scale industrial and commercial projects.

August 18 - Galveston Inc submits a *Preliminary Project Description* report to the BC Environmental Assessment Office and a similar project description was filed with the Canadian

Environmental Assessment Agency in September. The company envisions completion of the LNG terminal by November, 2008. The rationale for the LNG import project is based on supplying natural gas to Alberta's tar sands operations from a number of overseas LNG export terminals:

> In North America, Canadian natural gas has played an important role in meeting growing U.S. demand, but with the continuing growth in oilsands production, Canada will not be able to meet new US demand growth. A recent report indicates oilsands demand for natural gas is currently about 0.79 Bcf/d on an annualized basis. This demand is set to increase 2 to 4 fold as the development of the oilsands progresses.
>
> **Abundant World Natural Gas Reserves and LNG Potential**
>
> Natural gas reserves around the world are about 5,500 trillion cubic feet (Tcf), or about 60 times world annual usage. Much of this gas is "stranded" because it is located in regions disconnected from consuming markets. This has led to a growing LNG industry.
>
> The key development over the next ten years will be the rapid expansion of world wide liquefaction capacity. It is expected that by 2008, liquefaction will exceed the availability of regasification capacity by a considerable margin. There is massive growth of liquefaction facilities especially in the Pacific Basin, such as the Sakhalin Island project located off the east coast of Russia, Tangguh in Indonesia, Tiga in Malaysia and Gorgon in Australia. LNG production from these (and other) projects can be economically delivered to the West Coast of North America. Galveston will source LNG supply from these areas for use in the terminal.

In the National Energy Board's October 2000 report, *Canada's Oil Sands: A Supply and Market Outlook to 2015*, it states that "both integrated mining projects and thermal in situ projects use **substantial amounts of natural gas** as a fuel source in their operations," and that "the price of natural gas is an important determinant of the level of profitability for these projects."

> An assessment of natural gas requirements and electrical power generation related to oil sands development indicates that gas requirements would double to nearly 1 bcf/d by 2015, and that about 4.8 TW.h of generating capacity would be available to the Alberta power grid, also by 2015. This represents about 7 percent of Alberta's 1999 gas production and about 9 percent of its 1999 power generation capacity.

August - After holding 8 roundtable discussions with selected stakeholders in Vancouver, Calgary, Toronto, Ottawa, Montreal and Fredericton in February 2004, the National Energy Board publishes *Looking Ahead to 2010: Natural Gas Markets in Transition*. Based on its July 2003 report, *Canada's Energy Future - Scenarios for Supply and Demand to 2025*, the NEB summarizes scenarios that forecast "limited potential to increase natural gas supply" in Canada "while the demand for natural gas was likely to increase," suggesting the need for "import capacity for liquefied natural gas (LNG)." As stated on page 11 of the report, **"the greatest increase was expected to occur in the industrial sector largely due to the growth in" Alberta's tar sands developments**.

> The term unconventional gas typically refers to low-permeability reservoirs or "tight gas", shale gas, and CBM (increasingly referred to as natural gas from coal). In general, participants view that unconventional gas has the potential to increase overall natural gas

> production in the future. However, there is substantial uncertainty surrounding the economics and development of these resources in the period to 2010. The productivity of these wells are usually very low and a greater number of wells are needed to produce the gas since it tends to be found in deposits that extend over a large area.
>
> Looking at the overall North American context, participants generally believe that it will also be difficult to increase gas supply from other existing basins in the continent. As a result, there is tremendous interest to develop capacity to import LNG to North America. Across the country, participants were of the view that LNG would play a larger role in the future, particularly in the United States. (Pages 8-9)
>
> Scenarios for oil sands development indicate that the requirement for natural gas is likely to grow from the current 0.6 Bcf/d (17 million m3/day) to between 1.2 and 1.6 Bcf/d (34 to 45 million m3/day) by the end of the decade. Meanwhile, oil sands producers continue to examine ways to reduce their reliance on natural gas such as through the combustion or gasification of the bitumen itself, or through combustion or gasification of coal. Small scale nuclear power has also been raised as an alternative to gas. However, the general consensus of participants was that natural gas would continue to be the most economic and environmentally attractive fuel, at least until the end of the decade. (Page 12)

However, four years later, by 2008, the NEB's Canada-wide scenarios begin to shift dramatically to an over-supply of natural gas produced in western Canada.

September 14 - The BC Environmental Assessment office issues an order to **Kitimat LNG Inc.** regarding the project's Terms of Reference.

2005

January 6 - The National Energy Board and the Nova Scotia Department of Energy sponsor an LNG Safety Workshop held in Montreal. The meeting was held to scope "the potential for continued expansion of the LNG industry in North America."

April 13 - **Kitimat LNG Inc.** files its 60-page *Final Terms of Reference for an Environmental Assessment Certificate (Application) for a Liquified Natural Gas Receiving, Storage and Send-out Facility* to the BC Environmental Assessment Office. The report includes a description of a proposed TERMPOL review on large vessel transportation issues into Kitimat Arm fjord.

June 13 - the BC government accepts Kitimat LNG's application for an environmental assessment, marking the start of a 180-day review period. It includes a 45-day public consultation period from June 15 to July 30.

September - **Pacific Northern Gas Ltd.** (PNG) files Kitimat-Summit Lake (KSL) Natural Gas Pipeline Looping Project through Pacific Trail Pipelines for an environmental assessment process. The pipeline extends from Spectra Energy Transmission's pipeline at Summit Lake to the Kitimat LNG Inc. in Kitimat. A Project Description was filed on November 2, 2005, and the EAO issued an order on November 23, 2005 that the project was reviewable.

December - Kitimat LNG and the Haisla First Nation sign an agreement-in-principle for location of the proposed LNG plant on Bish Indian Reserve No. 6, at Bish Cove.

> In 2005 the Company commenced preliminary study and investigation of a project to loop its main line transmission system from Kitimat to Summit Lake (the "KSL Project"). The KSL Project would be required to provide gas transportation services for the proposed liquefied natural gas ("LNG") receiving and regasification terminal under development by Kitimat LNG Inc. to be located on the Douglas Channel approximately 15 kilometers southwest of Kitimat. **Kitimat LNG Inc.** is a private company headquartered in Calgary, Alberta. If the terminal is constructed as planned, the Company will seek the necessary approvals to reverse the flow of its pipeline and expand pipeline capacity from the current 115 million cubic feet ("MMcf") per day to accommodate the delivery of 610 MMcf per day from the terminal.
>
> On October 18, 2005 the Company engaged two international banks as co-arrangers for the project financing of the proposed KSL project. These banks were also concurrently engaged by **Kitimat LNG Inc.** as co-arrangers for the project financing of the proposed regasification terminal. (Source: **Pacific Natural Gas** Annual Information Form, 2005)
>
> In 2005, the Company commenced preliminary study and investigation of a project to loop its mainline transmission system from Kitimat to Summit Lake (the "KSL Project"). The KSL Project would provide gas transportation services for up to 1.0 billion cubic feet per day from the proposed Kitimat LNG Inc. liquefied natural gas ("LNG") receiving and regasification terminal (the "Terminal"), to be located on Douglas Channel approximately 15 kilometers southwest of Kitimat, to the Company's existing interconnection with the Spectra Energy ("Spectra Energy") transmission system. The KSL Project would entail the construction of approximately 470 kilometers of a 30 or a 36 inch diameter pipeline and associated compression facilities, at an estimated cost of $900 million to $1.2 billion. (Source: **Pacific Natural Gas** Annual Report, 2006)

2006

June 6 - BC government news release reports that Kitimat LNG Inc. "has received a provincial environmental assessment certificate for the construction and operation of a proposed liquified natural gas terminal at Bish Cove, following a comprehensive review by BC's Environmental Assessment Office."

June 6 - Adam Kreek publishes report, *The Albertan Tar Sands' Need for Natural Gas*:

> *Natural gas is currently a necessity for the production of the bitumen that lies within the tar sands. It is an industry rule that 1000 to 500 cubic feet of gas is needed to extract and upgrade one barrel of heavy crude, depending on recovery processes.*
>
> *The reserves of natural gas in Western Canada are limited and appear to have reached peak production. Peaking will cause costs to rise as demand outstrips supply. Finding the energy to power the tar sands may need to come from an area other than the Western Canadian Sedimentary Basin (WCSB). Construction of a Liquid Gas Transport terminal and pipeline is being pushed towards development in Kitimat, British Columbia.*

Gas could be brought in from all over the world to produce the oil in the tar sands. The consumption of foreign natural gases may affect Canada's international relationships, and the supply of oil coming from Northern Alberta.

The production of natural gas in Canada is currently experiencing a plateau, and it is the opinion of many including the National Energy Board (NEB) that the production of conventional gas has peaked.

The United States currently receives 85 per cent of its gas imports from Canada and will take whatever it can secure for future economic growth. Natural gas is necessary to make plastics, chemicals, pharmaceuticals, fabric for clothing and packaging. More importantly, 90 per cent of chemical nitrogenous fertilizer is made from natural gas, which has become indispensable to agribusiness.

The gas used to power the removal of bitumen from the tar sands currently comes from conventional sources in the Western Canadian Sedimentary Basin (WCSB), but new sources to fill increasing demand could come from coal beds, pipelines or liquid natural gas (LNG) terminals.

KSL Project Newsletter #1: June 2006

NEWSLETTER #1 / JUNE 2006

PNG Prepares to Expand Pipeline System

July 17 - PNG forms **Pacific Trail Pipelines Limited Partnership**, a 50-50 partnership between PNG and Galveston LNG Inc. (parent company of Kitimat LNG Inc.).

PTP and Kitimat LNG executed a Precedent Agreement to coordinate the process of obtaining authorizations for the KSL Project with the development of the Terminal. The agreement outlines, among other things, the key economic arrangements between PTP and Kitimat LNG, as well as the targeted timeline and key milestones for construction of the KSL Project and the Terminal. Upon completion of the KSL Project, and subject to regulatory and shareholder approvals, the Company's existing mainline transmission system will be transferred to PTP and integrated with the KSL Project facilities. The Company will continue to own and operate its existing gas distribution systems, including its Customer

Care Centre in Terrace. If the required approvals and LNG supply are obtained, PTP expects to commence construction of the KSL Project facilities by the fourth quarter of 2008. (PNG Annual Information Form, 2006)

A key component of the BCEAO process is consultation with and accommodation of First Nations interests, as the KSL Project traverses the claimed traditional territory of 17 First Nations. We are meeting with First Nations representatives to ensure the interests of all affected First Nations are accommodated. (PNG Annual Report, 2006)

July 18 - Edmonton Journal article, *Kitimat LNG raises interest from oilsands*. Following its intention to supply natural gas to Alberta's tar sands in its August 2004 Terms of Reference report to the BC Environmental Assessment Office, the media eventually report that the proponent is receiving interest from the tar sands developers.

August 28 - **Kitimat LNG Inc.** receives a federal environmental permit to build the first LNG terminal on the west coast of Canada and the United States. In a press statement, Kitimat LNG president Rosemary Boulton states: "Demand for oilsands production and the natural gas to power these projects will grow, making the project attractive to offshore suppliers."

October 18 - In a press release by Kitimat LNG Inc.: "The terminal will deliver gas via a pipeline approximately 14 kilometers long, into the Pacific Northern Gas pipeline. The gas will then be transported to the interconnection of the existing Duke Energy's Westcoast Energy Main gas transportation system." "The company announced in late September it had signed a Heads of Agreement (a precursor document to a formal contract) with **Liquefied Natural Gas Ltd.** of Australia, which would see the Australian company supplying 1.8 million metric tones per year of LNG, or, 25 per cent of the terminal's capacity. For the terminal to be economically viable, it requires a supply feed of close to capacity, she says, adding, "we expect the rest of supply to be in place within the next year."

Photo of Gosnell wetlands, just east of the rising Coast Mountain Range, through which the pipeline route may travel.

2007

January 2 - **Duke Energy Corporation** spins off its gas business, including **Westcoast Energy Ltd.**, to form **Spectra Energy Corp.** According to online Wikipedia, **Spectra Energy** "may be considered the single largest private-sector source of greenhouse gases in British Columbia." (Reference: Globe and Mail newspaper, March 29, 2007)

> On January 2, 2007, **Duke Energy** completed the spin-off of its natural gas businesses, named **Spectra Energy Corp.** (Spectra Energy), including its wholly-owned subsidiary **Spectra Energy Capital, LLC** (Spectra Energy Capital, formerly Duke Capital LLC). The natural gas businesses spun off primarily consisted of Duke Energy's Natural Gas Transmission business segment and Duke Energy's 50% ownership interest in **DCP Midstream, LLC** (DCP Midstream, formerly Duke Energy Field Services, LLC), which was part of the Field Services business segment. The results of operations of these businesses are presented as discontinued operations in the accompanying Consolidated Statements of Operations for all periods prior to the spin-off. See Note 1 to the Consolidated Financial Statements, "Summary of Significant Accounting Policies."
>
> **1. Summary of Significant Accounting Policies**
>
> The new natural gas business, which is named **Spectra Energy Corp.** (Spectra Energy), consists principally of certain operations of **Spectra Energy Capital, LLC** (Spectra Energy Capital, formerly Duke Capital LLC), primarily Duke Energy's former Natural Gas Transmission business segment and Duke Energy's former Field Services business segment, which represented Duke Energy's 50% ownership interest in DCP Midstream, LLC (formerly Duke Energy Field Services, LLC) (DCP Midstream).
> (Source: **Duke Energy Corporation** 2007 Annual Report - U.S. Securities and Exchange Commission, Form 10-K)

July 25 - **Pacific Trail Pipelines Limited Partnership** files application with the BC Environmental Assessment Office for an environmental assessment certificate for the KSL (Kitimat-Summit Lake Pipeline Looping) project.

October 11 - Pacific Trail Pipelines' application with B.C. Environmental Assessment Office for an EAO certificate is accepted.

2008

June 27 - BCEAO issues EA certificate for the $1.1 billion Pacific Trails Pipeline. Announcement made by Environment Minister Barry Penner and Energy Minister Richard Neufeld.

September - Kitimat LNG reverses its originating plan from importing gas to exporting gas, and begins seeking interested international buyers. Kitimat LNG vice-president Ilene Schmaltz stated a few months later, "large Canadian and major international energy players have expressed concrete interest in our project through the process."

November 14 - Kitimat LNG Terminal submits an Application for Certificate Amendment (with attached appendixes) to the BC Environmental Assessment Office to revise and reverse its position from importing to exporting natural gas ("change in utilization"), changing the intent to a $3 billion LNG "liquefaction" terminal for a projected 60 LNG mass marine export tankers per year, a drop from 90 annual tankers from the original import proposal. Nevertheless, the proponents describe the pipeline as maintaining "bidirectional" purpose.

> Since issuance of the Environmental Assessment Certificate in 2006, KLNG has been actively pursuing LNG supply for the terminal. However, over the past two years several fundamental changes in the global marketplace have affected the available supply. Two of the most important changes have been an increase in LNG demand within the Asian markets and delays in completing liquefaction projects around the Pacific Rim.
>
> At the same time that LNG demands have increased around the world, there have been major natural gas discoveries in North America and, in particular, the Horn River and Montney fields in British Columbia. The projected reserves and deliverability over the next few years have significantly changed analysts' perception of gas supply available in North America, reducing the need for new LNG import terminals.
>
> The resulting supply/demand imbalance has led to significant price increases for LNG since the Kitimat project was originally proposed in 2004 and it is now difficult to attract long-term supplies of LNG for delivery to the North America market. This challenge has affected viability of the terminal development in Kitimat.
>
> KLNG has an opportunity to take advantage of these new market dynamics by changing the business model of the Kitimat terminal to include an export facility. The revised business model, supported by strong economics, can effectively take advantage of the opportunity to liquefy natural gas for export now and in the future.

December 10 - The federal Environmental Assessment office notifies Kitimat LNG that it does not require a new federal environmental assessment for its conversion application to export LNG.

2009

January 7 - The BC EAO approves Kitimat LNG Inc.'s project amendment application.

January 13 - Kitimat LNG Inc. signs a Heads of Agreement with **Mitsubishi Corporation** equity stake and terminal capacity, for 1.5 million tons/year of LNG, a 30% annual interest. Mitsubishi vice president Kazuyuki Mori states "Mitsubishi is an industry leader in the global LNG sector, and handles nearly half of the LNG imports to Japan."

February - A three-part economic and partnership agreement for the Haisla First Nation (Kitimat) is tabled by its Vancouver-based lawyers, Donovan & Company, concerning the development of the Pacific Trails Pipeline: The Limited Partnership Agreement; the Participation Agreement; and the Economic Partnership Agreement. The KLNG Benefits Agreement provides the Haisla with 350,000 shares in Kitimat LNG Inc. The 93-page document describes how the provincial government and the Pacific Trails Pipeline Limited Partnership (PNG and Galveston Inc) met with the 16 affected First Nations and created a "main table" forum and a "working group" to represent the interests of the First Nations. In this agreement, the BC government would "pay up $35 million" to a First Nations partnership, where the "First Nations would be required to invest all but $3 million of the money to buy a share of the pipeline enterprise. The First Nations, for their part, would agree that the Province has consulted and accommodated their Aboriginal rights and title with respect to the pipeline." In the long set of stipulations in the draft document, the Haisla promise not to "take any actions of any kind, including court actions, to directly or indirectly challenge, prevent, hinder or delay the Pacific Trails Pipeline Project."

March 10 - Fisheries and Oceans Canada and Transport Canada gives approval for the Pacific Trails Pipeline to proceed pursuant to the CEAA.

March 16 - Pacific Trails Pipeline project receives CEA approval.

April 14 - BC Utilities Commission, which will regulate the Pacific Trails Pipeline, provides letter of agreement. The Pacific Trails Pipeline will send an application to construct and operate the pipeline sometime in 2011.

April 15 - A news bulletin announces that "First Nations along the route of a proposed natural gas pipeline in northern B.C. are signing onto a partnership with the province and the natural gas industry in exchange for $35 million in equity and incentives."

June 8 - Kitimat LNG enters a Memorandum of Understanding (MOU) with **Korea Gas Corp.** to acquire 2 million tons of LNG per year from Kitimat terminal for 20 years, about 40% of the proposed 5 million tons/year output (685 million cubic feet per day).

July 6 - Kitimat LNG enters Memorandum of Understanding (MOU) with Spain's **Gas Natural**, which allows **Gas Natural** to acquire 30% of the proposed LNG output from Kitimat. **Gas Natural** delivers LNG to Spain, France, Italy and Latin America, and has a joint venture with **Repsol** which owns a fleet of LNG vessels.

July 15 - **Kitimat LNG** signs natural gas supply agreement with **EOG Resources Canada** and **Apache**, both based in Houston, Texas.

July 16 - The Vancouver Island Tides magazine reports that there are presently "some 270 LNG tankers operating around the world. These are big ships: the typical tanker has a capacity of some 140,000 - 180,000 cubic metres, or some 1.9 million cubic feet, and is about 280 metres long. (Qatar is currently building LNG tankers which are 50% larger in capacity.)"

2010

Aboriginal Skills and Employment Partnership (ASEP) Program, through the federal Human Resources and Skills Development Canada, initiates the Pacific Trails Pipeline (PTP) ASEP Training Society. It was announced that the PTP project would receive $9 million under Canada's Economic Action Plan. The partners (stated on the ASEP website) include:

- First Nations PTP Group Limited Partnership ($1 million in funding)
- Pacific Trail Pipeline ($1,231,000 in funding)
- Kitimat LNG ($2,466,000 in funding)
- Community Partners ($1,647,000 in funding)

- Pipeline First Nations, 15 communities ($3,095,887 in funding). The communities: Haisla FN, Kitselas FN, Lax Kw'alaams Band, Lheidli T'enneh Band, McLeod Lake Indian Band, Metlakatla FN, Nadleh Whut'en FN, Nak'azkli Band, Neetahi Buhn Band, Saik'uz FN, Skin Tyee FN, Stellat'en FN, Ts'il Kaz Koh FN, West Moberly FN, Wet'suwet'en FN.

January 10 - **Apache's KM LNG Operating General Partnership** acquires 51% interests in the assets of **Kitimat LNG Inc.**, which was owned by Calgary-based **Galveston LNG**. "**KM LNG Operating General Partnership** is a general partnership between Calgary-based **Apache Canada KMM ULC** and **Apache Canada Ltd.** (managing partner, and wholly owned affiliate of **Apache Corp.** which operates in the Horn River Basin)." The proposed LNG plant in Kitimat is initially forecast to handle 700 million cubic feet of gas per day (about 20 million cubic metres), representing about 20% of BC's annual production (based on 2009 data), or about 5 million metric tons of LNG per year. Deals are being made with two buyers: **Korea Gas Corp.** (the world's largest importer of natural gas) and **Gas Natural** (Spain & Latin America).

January 14 - **Apache Corp.** joint partnership with **Pacific Northern Gas**. "Shares of Vancouver-based **Pacific Northern Gas** jumped $1.35, or seven per cent, to $20.65, trading as high as $21.49, after Houston-based **Apache** agreed to buy 51 per cent of the Kitimat liquefied natural gas export terminal. The $3-billion terminal would ship up to 700 million cubic feet a day, beginning in 2014. **Apache** is also buying a 25.5-per-cent stake in its Pacific Trail Pipelines limited partnership that would build the $1.2-billion pipeline loop to supply the terminal."

March 1-5 - Global LNG Summit in Amsterdam.

April 18-21 - 16th International Conference on LNG.

May 18 - **EOG Resources** buys Calgary-based **Galveston LNG Inc.** for $210 million, acquiring the remaining 49% of **Kitimat LNG Inc.** from **Galveston LNG**, with **Apache** owning the remaining 51%. **Galveston Inc.** owned 24.5% interest in Pacific Trails Pipeline.

August 20 - Two events in Prince George and Kitimat, sponsored by the Pacific Trails Pipeline Aboriginal Skills Employment Partnership, herald the new partnership for employment opportunities for First Nations to construct the proposed Pacific Trails Pipeline project.

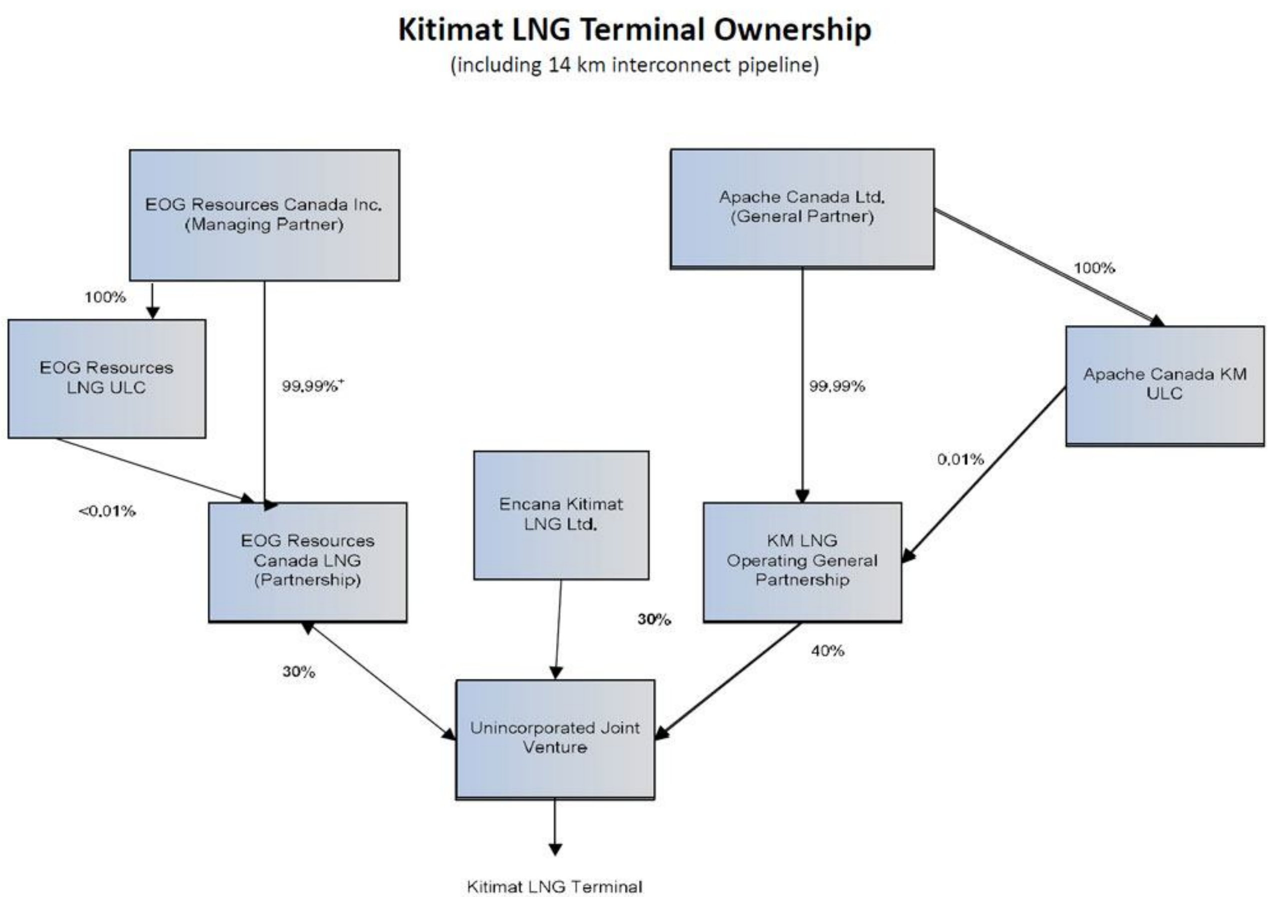
November 23 - The Haisla Nation ratifies a 49 year lease construction and operation lease with **Apache Canada** for the Kitimat LNG terminal.

December 9 - **KM LNG Operating General Partnership** applies to the National Energy Board under section 117 of the *National Energy Board Act* (NEB Act) for a long-term (20-year) licence to export natural gas as liquefied natural gas (LNG) from Canada to markets primarily located in Asia Pacific, doubling its original 700 million cubic feet/day export volume of LNG. The application includes a set of documents that describe the project proposal.

> For the 20-year export licence, KM LNG has requested terms and conditions that include:
> (a) an annual volume of natural gas not exceeding 10 million tonnes of LNG, equivalent to 13,300,000 10^3m^3 or 468 billion cubic feet (Bcf) of natural gas;
> (b) term volume of natural gas not exceeding 20 times the annual volume, or 200 million tonnes of LNG, equivalent to 265,000,000 10^3m^3 or 9,360 Bcf of natural gas;

(c) an annual tolerance that may exceed the annual exported volumes stated above by 10 per cent;
(d) an export point located at Bish Cove, near the Port of Kitimat, BC and;
(e) the filing with the NEB of all LNG sales contracts under which all LNG volumes will be exported.

KM LNG has stated that it will be the operator of a proposed natural gas liquefaction export terminal to be constructed and operated at Bish Cove, near the port of Kitimat, British Columbia (Kitimat LNG Terminal or Terminal). Development of the Terminal is proceeding by way of a joint venture arrangement that currently consists of affiliates of **Apache Canada Ltd.** (Apache) and **EOG Resources Canada Inc.** (EOG). Apache Canada Ltd. is an affiliate of Apache Corporation and EOG Resources Canada Inc. is an affiliate of EOG Resources, Inc. Apache and EOG hold a 51 per cent and 49 per cent participating interest, respectively, in the joint venture and corresponding entitlement to the physical capacity of the proposed Kitimat LNG Terminal.



In Apache's, EOG's, and Encana's revised May 16, 2011 application information to the National Energy Board is an updated version of the new ownership arrangement under the Kitimat LNG terminal partnership.

2011

January 1 - According to “additional evidence” filed with the National Energy Board by the Kitimat LNG export applicants, “**Kitimat Partnership** and **Kitimat ULC** each underwent name changes. **Kitimat Partnership** changed its name to **EOG Resources LNG** and **Kitimat ULC** changed its name to **EOG Resources LNG ULC**. In addition, as a result of a series of amalgamations between December 30, 2010 to January 1, 2011, Kitimat LNG Inc., Galveston LNG Inc., EOG Resources LNG Inc. and EOG Resources Canada Inc. **were all amalgamated** and continued in the form of **EOG Resources Canada Inc.**”

January - The “world’s leading LNG publication”, LNG Journal, with the promotional front page feature, *Kitimat LNG project envisages sale premium of around $10 to U.S. price*. The article reports: “Due to changing gas market conditions in North America, where unconventional gas has led to oversupply in the US and a reduction in Canadian pipeline gas exports across the border, the project was revised to be an export plant.”

Kitimat LNG project envisages sale premium of around $10 to US price

LNG Journal North America Editor

The Kitimat LNG project being developed by Texas-based Apache Corp. is making progress in its plan to export Canadian shale gas as LNG to the Asia-Pacific region at a premium of around $10 per million British thermal units or more to prevailing US natural gas prices.

KM LNG, originally developed as an import facility, will become Canada’s first LNG liquefaction plant when it is completed by around 2015 at Bish Cove, north of Vancouver, near the port of Kitimat, British Columbia, at a cost of more than $4 billion.

Apache as the majority shareholder formally applied in December to the Canadian National Energy Board for a licence to export LNG for a period of 20 years.

Its filing to the NEB included more details on company structures, agreements, feed-gas resources and the project’s marketing outlook in the Asia-Pacific contributed by a leading US consultancy.

The choice of Bish Cove at Kitimat is supported by the local First Nation population and offers a deep channel for shipping and easy access to existing and planned pipeline infrastructure in

The Kitimat LNG project in Western Canada will be able to deliver to premium markets in China, Japan and Korea and benefit from favourable shipping costs

In addition to the income from the lease, the Haisla First Nation also has rights to acquire an equity position in the Pacific Trail Pipeline that will transport gas to the plant for liquefaction.

Shale feed-gas

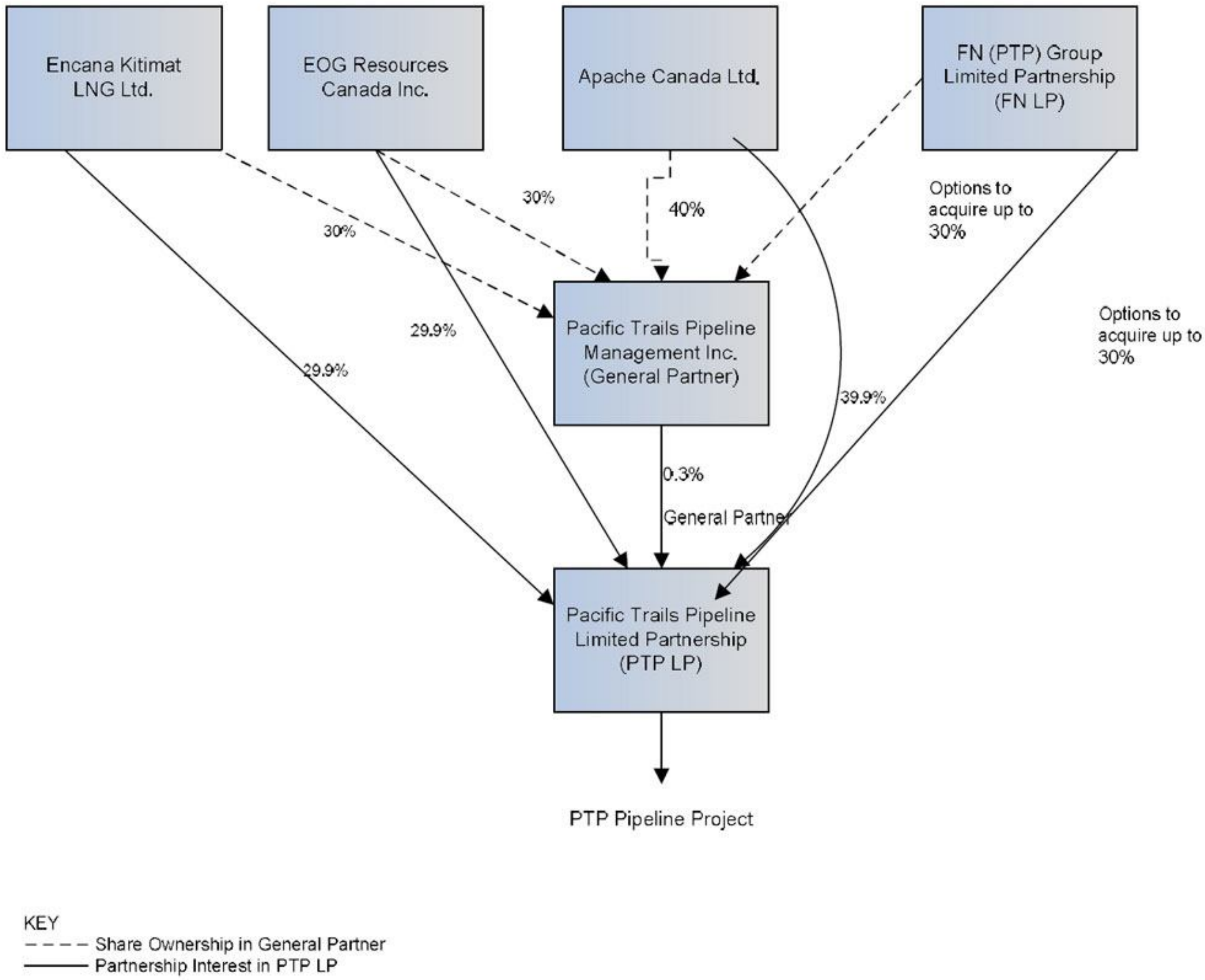
The majority of the feed-gas supply requirements for the plant will come from “prolific unconventional shale gas resources located in the north-east region of British Columbia,” KM LNG said in its

However, there could also be enough feed-gas for 10 MTPA of production per annum after a second-phase expansion.

The marine facilities will also be capable of handling LNG carriers of up to 266,000 cubic metres capacity. The LNG energy content is envisaged at 1075 Btu.

The project will also include a 14-kilometre spur pipeline that will connect the plant to the Pacific Trail Pipeline. The PTP will transport gas from the Spectra BC pipeline at Summit Lake.

Pacific Trail Pipeline Ownership



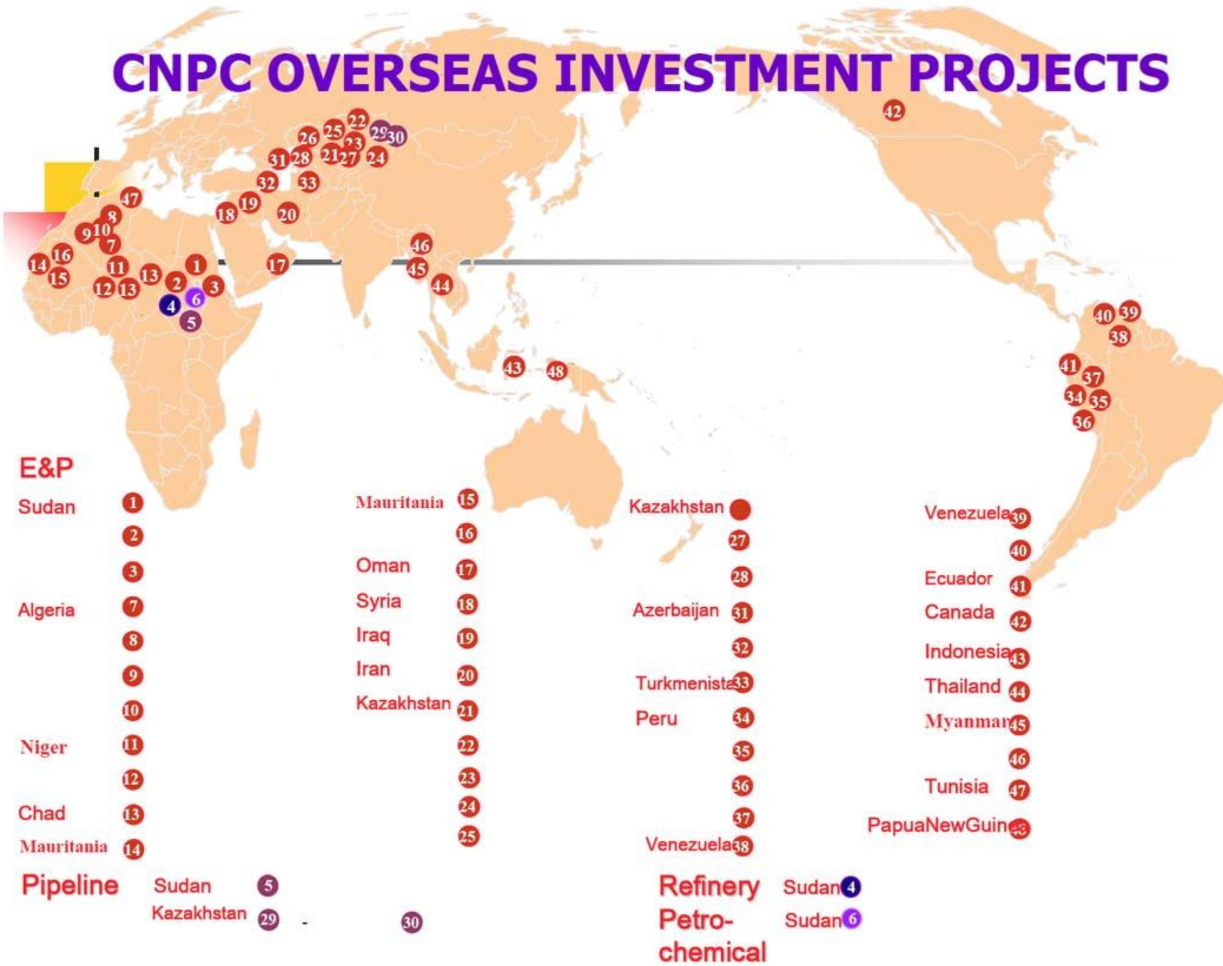
In Apache's, EOG's, and Encana's revised May 16, 2011 application information to the National Energy Board is an updated version of the new ownership arrangement under the under the Pacific Trails Pipeline partnership.

February 7 - Kitimat LNG partners **Apache Canada Ltd.** and **EOG Resources Canada Inc**. obtain 100% shared interest in the PTPLP, Apache with 51% and EOG with 49%. The new agreement will see PNG operate and maintain the proposed pipeline. Founded in 2004, Galveston LNG Inc. is now a subsidiary of EOG Resources Canada, Inc.

March 11 - According to "additional evidence" filed with the National Energy Board, on March 11 "**EOG Resources Canada Inc.** and **EOG Resources LNG ULC** formed a new general partnership, **EOG Resources Canada LNG**, and the partnership interest of EOG Resources Canada Inc. in EOG Resources LNG was transferred to **EOG Resources Canada LNG**. As a consequence, a 49% undivided interest in Kitimat LNG Terminal is now owned by **EOG Resources LNG**, which is, in turn, an indirect wholly owned subsidiary partnership of EOG Resources Canada In., a subsidiary of EOG Resources, Inc." (Are you as confused as I am?)

March 18 - Pending regulatory approval, **Encana Corporation** acquires a 30% interest in the Kitimat LNG and Pacific Trails Pipeline. Apache sells down 11% of its equity and EOG sells down 19% of its equity. The proposed construction costs for the LNG plant is now at $4.5 billion, and the proposed pipeline at over $1 billion.

Photo of Summit Lake facility north of Prince George, the site of Pacific Northern Gas's current westward gas extension pipeline to Prince Rupert, and the site of the new proposed 36 inch diameter pipeline link to Kitimat.



2008 global investment diagram showing the overseas energy ownership assets of China's state-owned China National Petroleum Corporation (CNCP). PetroChina, as an arm of CNCP, has investments in Alberta's tar sands and now a partnership arrangement with Encana Corporation. CNCP's assets have grown since 2008. Wikipedia reports that as of September 28, 2010, CNCP is "the world's most valuable company by market value," estimated at about $300 billion, surpassing Exxon Mobil's former top market value in the Global 500 chart.