

MARKET POTENTIAL FOR CANADIAN LNG

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ABSTRACT

There are many questions facing the Global LNG industry. What role can North America play in this, other than diversity of supply? Global LNG exports to Asia Pacific region – when, how much, and from where? The countries from the supply side would be Australia, Canada, Russia and Qatar. The countries from the demand/market side would be China, Japan, South Korea, Taiwan. What is the future of oil indexation in the Asia Pacific region? A look at the various LNG pricing and costs for LNG imports in Asia including JCC? What is the role for LNG in the transportation sector in North America? Will the Chinese shales affect the LNG business or will it be the biggest engine of growth? Role played by the earthquakes that might further boost the LNG demand in Japan. Is LNG a long-term business-what are the various drivers that might impact the business in the long-term outlooks?

Abbreviations (used in the paper): LNG: Liquefied Natural Gas, Tcf: Trillion cubic feet, GDP: Gross domestic product, BCFPD: Billion cubic feet per day, Mtpa: Million Tons per annum, SWOT: Strength, Weakness, Opportunities and Threats

Note: The views expressed in the paper are those of Paul Cheruvathur's research and do not bear the views of his employer.

INTRODUCTION – NATURAL GAS: FUEL OF THE FUTURE

The “unlocking” of unconventional¹ gas resources through the combined use of horizontal drilling and hydraulic fracturing have redefined the North American natural gas market landscape. These technological break-through have facilitated a significant increase in North American natural gas reserves at a relatively low cost. The North American market has therefore shifted from one of supply scarcity to that of supply-on-supply competition. Natural gas is now the fastest growing fuel source in the world especially so in North America², it is not only domestically abundant but a cleaner and secure source of energy. Further as a substitute fuel, natural gas also presents an ideal solution to the problem of decreasing supplies of ‘economical’ crude oil. Hence we can rightly term natural gas as a fuel of the future.

Tremendous demand for Natural Gas: Along with an increase in natural gas supplies around the world, there is a simultaneously huge demand growth for natural gas especially in the Asian markets. During the next two decades the demand for imported gas by China, India, South Korea, and Japan is projected to double over 2009 levels. There will be increasing pressure on the rapidly developing economies of China and India to substitute “clean” fuels for coal to reduce pollutants and carbon dioxide emissions.³ Electricity generated by natural gas can produce less than half of the carbon dioxide emissions that an equivalent amount of electricity generated by coal combustion. For the coming decades, globally the consumption of natural gas is predicted to increase 38% by 2035, and regionally in Asia to increase as much as 94% by 2035.⁴Such is driven both by the growing demand in energy and the decreasing relative price of natural gas against crude oil. Apart from meeting the future energy demand in a constrained crude world, natural gas provides a clear

¹ According to the IEA WEO 2012, unconventional gas would account for nearly half of the increase in global gas production to 2035

² BP 2012 - Global gas supplies are forecasted to increase to about 65% by 2040 with 20% of production occurring in North America

³ (BP, 2011)- In 2010, China and India accounted for 48 percent and 8 percent, respectively, of world coal consumption. For these countries coal is used for the generation of electricity

⁴ IEA 2010

advantage in the area of environmental impact, more affordable, reliable and a higher energy efficiency source of fuel.

LNG trade is gaining momentum: The main reason for liquefying natural gas is to store and transport it by sea to a better paying market. Japan, South Korea and Taiwan with very limited indigenous production predominately meet their natural gas demand through imports of LNG. These three countries represent three of the world’s largest LNG consumers. In recent years, with active policy support China and India have increasingly looked to LNG imports to augment other sources of gas supply in order to meet their consumption requirements. Together, these five countries make up over 62 percent of the world’s LNG consumption in 2009. LNG import terminals are also currently under construction in Pakistan, Singapore, and Thailand which will add to the region’s growing LNG requirement. The historical and projected growth in Asia-Pacific natural gas demand has led to significant development of LNG production and export capacity from gas exporting jurisdictions around the world.

The traditional LNG suppliers: The majority of new LNG supply added in the period 2007-2010 has been from the Middle East (Qatar, Yemen), Indonesia, and Russia. All of these producers had long-term contracts and were at least partly sponsored by Northeast Asian buyers. In the period 2010 to 2015, significant additional liquefaction is also being added in the Pacific Basin (Australia, Papua New Guinea) and the Middle East (Qatar, Iran), with smaller quantities from Africa. While post 2015, Australia, US, East Africa along with *Canada* could be playing a bigger role as major LNG suppliers.

The figure in the next page clearly indicates the growing importance of natural gas a fuel of choice.

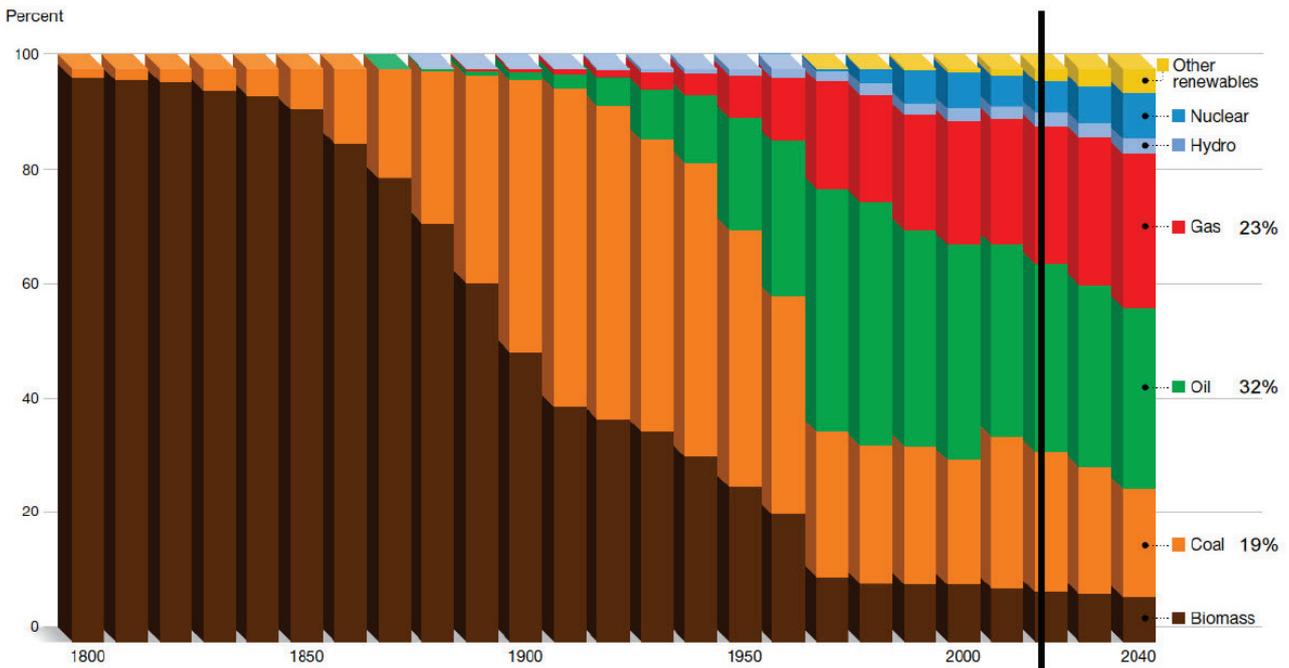


Figure 1: Global fuel mix by decade
Source: Exxon Mobil 2013, The Outlook for Energy: A View to 2040

Natural gas supply in Western Canada

We in Western Canada are blessed with a plethora of world class natural gas (unconventional) resources that can easily meet its internal and external demand. The Canadian Society for Unconventional Resources (CSUR) estimates the country's original gas-in-place at over 4,000 TCF, with 3,323 TCF from unconventional resources such as tight gas, shale gas, and coal bed methane.⁵ Utilizing existing technology, the marketable natural gas resource value is estimated to range between 700 TCF and 1,300 TCF⁶.

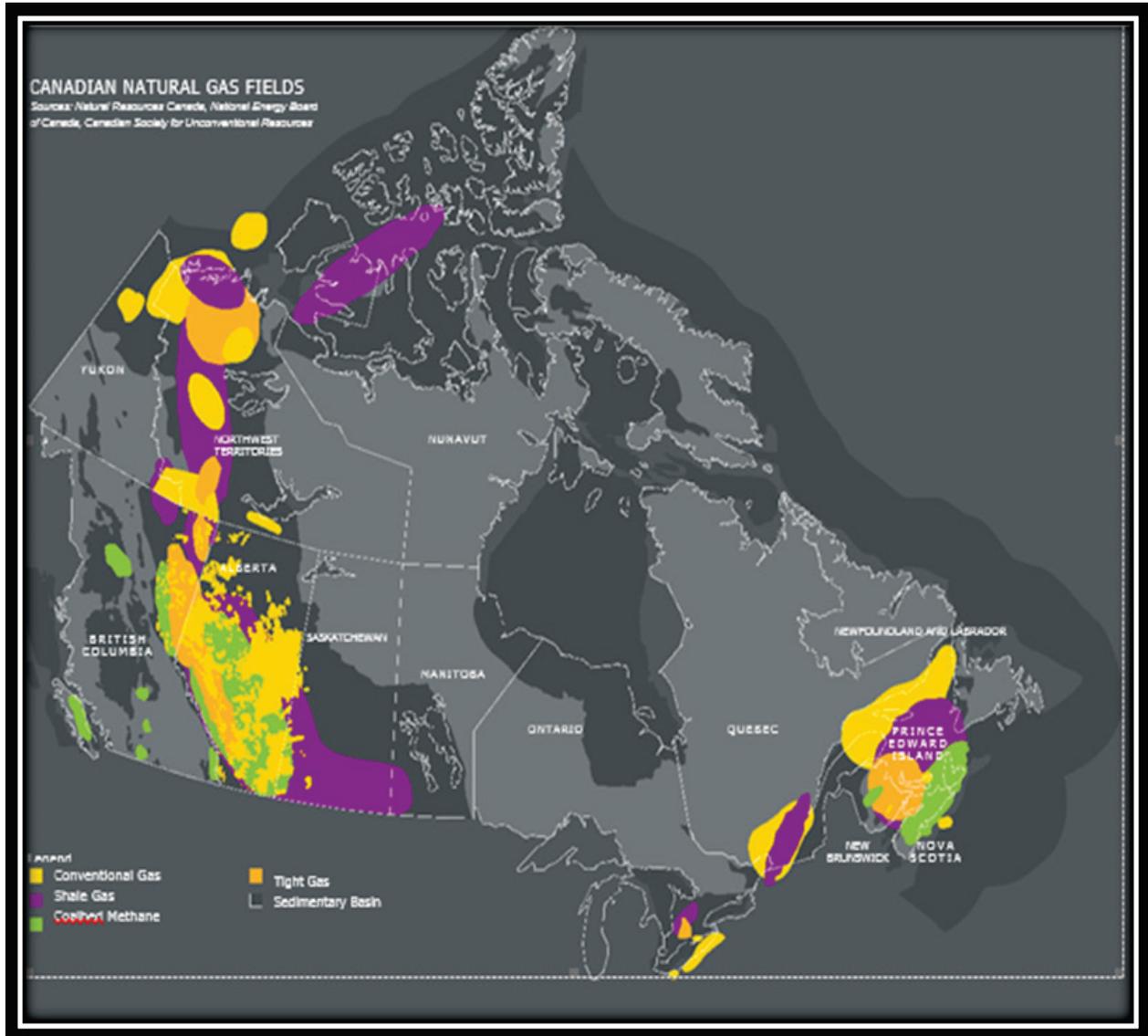


Figure 2: Canadian Natural Gas Plays
Source: Canadian Centre for Energy Information

⁵ Dawson, Mike, "Unconventional Hydrocarbon Resources in Western Canada, Opportunities for Growth and Sustainability", Asia Canada Unconventional Resources Forum, Canadian Society for Unconventional Resources, July 11, 2012, http://www.csur.com/images/CSUG_Events/other/ACURF/Dawson.pdf

⁶ Dawson, Mike, "Unconventional Hydrocarbon Resources in Western Canada, Opportunities for Growth and Sustainability", Asia Canada Unconventional Resources Forum, Canadian Society for Unconventional Resources, July 11, 2012, http://www.csur.com/images/CSUG_Events/other/ACURF/Dawson.pdf

Importance of Natural Gas to Western Canada:

The natural gas industry in Western Canada is not only an important part of both Alberta's⁷ and British Columbia's economy, but also to Canada as a whole. The economic value of the natural gas industry, as measured by value added, exceeded \$106 billion in 2008, accounting for 6.7% of Canada's total output. In Canada, total value added from natural gas direct activities approached \$73 billion, while indirect and induced natural gas activities contributed nearly \$34 billion.⁸

Indirect and induced impacts of Western Canada's natural gas industry are also felt in other provinces. Ontario is a major hub for Canada's manufacturing, finance, and services industries with steel and other primary goods businesses that support the natural gas machinery industry in Canada. The support of out-of-province natural gas activities contributes to a sizable multiplier (total relative to direct in-Ontario jobs). Quebec's manufacturing and professional services industries support the natural gas industry in Canada's main producing provinces. Quebec is thus another province that benefits substantially from indirect and induced impacts of direct natural gas activities in Alberta.⁹

Traditional Markets for Western Canadian Gas: The domestic market is small, relative to Canada's current and future production potential. Western Canadian gas producers have only exported gas via pipeline to markets in the United States. Abundant supplies of U.S. shale-sourced gas located close to eastern markets has lowered demand for Western Canada's natural gas supplies, as well as reduced the need for long haul pipelines connecting conventional gas supplies from Western Canada to eastern markets of the United States. Canadian pipeline gas exports to the US have declined by 17 percent, from 3.8 TCF in 2007 to 3.1 TCF in 2011, pipeline gas imports from the US have nearly doubled over the same five years, to just under 1 TCF. This trend is expected to continue, and by 2022. Energy Information Administration is projecting that the United States will become a net exporter of natural gas.¹⁰ Figure below displays the change in pipeline gas trade between Canada and the US over the last five years.¹¹

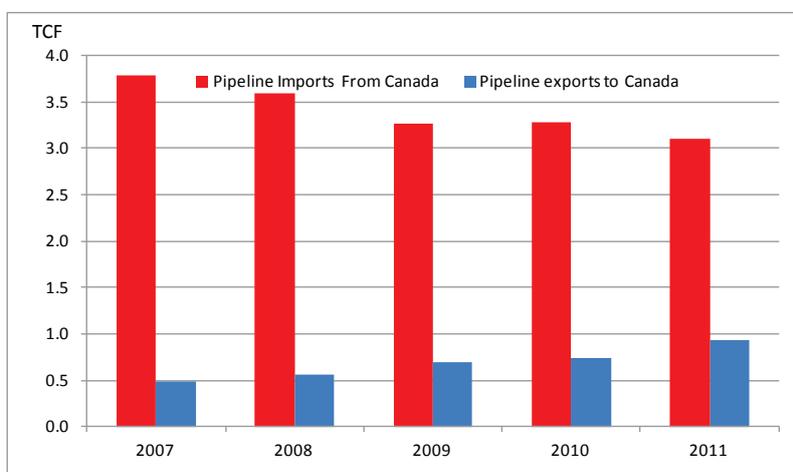


Figure 3: US Pipeline Gas Imports from, and Exports to, Canada, 2007-2011

Source: US EIA

⁷ Labour income from direct, indirect, and induced natural gas jobs specifically in Alberta totaled \$17.9 billion in 2008. Value added in Alberta from direct, indirect, and induced natural gas related activities totaled \$80.8 billion in 2008 (nominal Canadian dollars), accounting for 27.7% of Alberta's GDP

⁸ Canadian Energy Resources Institute, 2009.

⁹ Canadian Energy Resources Institute, 2009

¹⁰ "Annual Energy Outlook 2012", US Energy Information Administration, June 25, 2012.

¹¹ "US Natural Gas Imports & Exports 2011", US Energy Information Administration, July 18, 2012.

<http://www.eia.gov/naturalgas/importsexports/annual/index.cfm#tabs-supply-2>

Increases in United States' domestic supply of gas has reduced North American gas prices as a result, netbacks to Western Canadian producers has decreased substantially. In Western Canada, this excess supply of Natural gas has forced industry stakeholders to explore new gas export markets and this has never become more apparent.

LNG to Asia: A new incremental gas market for Western Canadian Gas:

Fortunately, Canadian gas producers have an opportunity to develop markets in Asia where buyers are seeking stable, long-term LNG purchase agreements with reliable gas producers in politically stable countries. Premium price Asian Markets like Japan, South Korea and China are seen by Western Canadian producers as a viable alternative. Most of the gas meant for the purpose of LNG would be sourced primarily from British Columbia's gas plays – Horn River, Liard and Cordova gas plays and from Alberta's Montney.

Why Asia is interested in Canada: Asian LNG buyers are showing strong interest in developing new LNG supply sources especially with many of its existing long term contracts ending around 2014-2016 time frame (e.g. China to fuel its massive modernization, and Japan/ South Korea to diversify its fuel supply along with several other countries like India).

The Asian LNG importers may be concerned by long-term gas price deliverability. Asia is used to pricing certainty via contract. More importantly, existing Asia-Pacific LNG suppliers will not want to see price pollution from North American LNG supplies and it is these suppliers who are the most likely aggregators of North American LNG. It remains to be seen how Canada's West Coast exports will price into Asia – either as a mark-up to the prevailing Henry Hub plus liquefaction costs or follow the current practice in Asia i.e. LNG pricing correlated to crude.

OBJECTIVES AND METHODOLOGY OF THIS STUDY

What roles can North America specifically Western Canada play in the LNG world, other than diversity of supply?

The purpose of the report is to answer two fundamental questions – one based on supply-demand of LNG and the other based on pricing.

- Is there an opportunity to export natural gas via LNG to the Asian markets, especially at a time when there is growing LNG liquefaction terminals around the world?
- Is there a potential for Canada to export its cheap natural gas to premium priced markets like Asia and get high netbacks?

For helping answering these two questions, it is important for us to track some key information to further explore into the following topics

- Who are the key global suppliers of LNG to the Asian Pacific region
- What are the potential markets for Canadian LNG specifically looking at China, Japan, and South Korea?
 - Will the Chinese shale's affect the LNG business or will it be the biggest engine of growth?
 - Role played by physical calamities like earthquakes that might further boost the LNG demand in Japan.
- LNG Pricing:
 - What is the future of oil indexation in the Asia pacific region? A look at the various LNG pricing and costs for LNG imports in Asia including Japanese Crude Cocktail (JCC). ?
- Is LNG is a long-term business opportunity for Canada?
 - A SWOT analysis will be conducted to show why Canada is a good fit to be a long term supply partner for the Asian countries.

The analysis will not account for yet unknown or unapproved trade or environmental policies which could alter the future of natural gas trade and consumption.

It will also assume the following

- Development of the other unconventional gas supply around the world beyond North America will be limited e.g. China's unconventional gas, while substantial, will take a longer time to develop due to environmental challenges.
- We will see an overall low Henry Hub natural gas prices and very little regulatory restrictions on upstream unconventional gas development.
- Oil Indexed pricing will continue to be the main pricing mechanism used in the Asian markets.
- North America remains in a gas glut world and Canada is losing its traditional US markets and it needs to be actively involved in shipping gas via LNG to the Asian markets.

GLOBAL LNG SUPPLY - DEMAND STORY:

The graph below clearly indicates the existing supply-demand gap in the Global LNG supply chain and the potential for LNG export terminals. This gap in supply results in the underlying market opportunity for Canadian LNG projects. Over the next two decades, LNG will play an important role in meeting the increasing global demand for natural gas. The largest demand growth potential exists in the Asia Pacific market, where Japan and South Korea will continue to dominate along with aggressive growth markets like India and China.

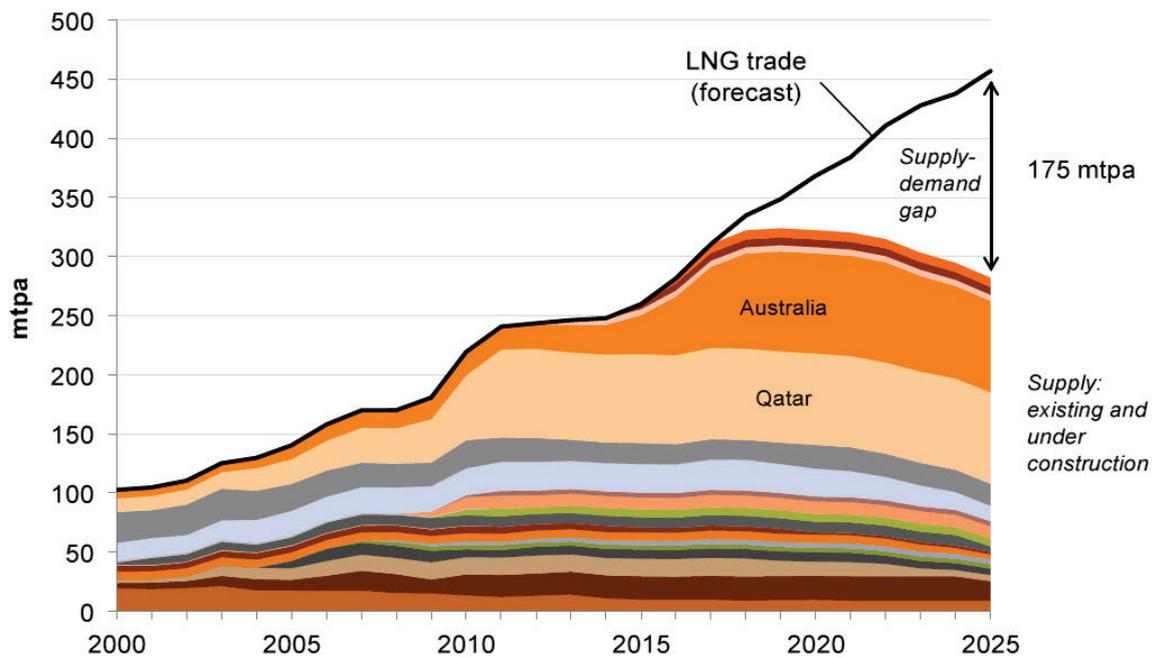


Figure 4: LNG Supply Challenge
 Source: BG Group Interpretation of Wood Mackenzie data (August 2012)

According to CERI by 2035 global natural gas demand could increase by more than 50 percent. The two figures below clearly indicate that presently the global regasification capacity exceeds the global liquefaction capacity i.e. The supply demand gap that will exist between new liquefaction facilities (i.e. Exporters) and new regasification facilities (i.e. Importers).

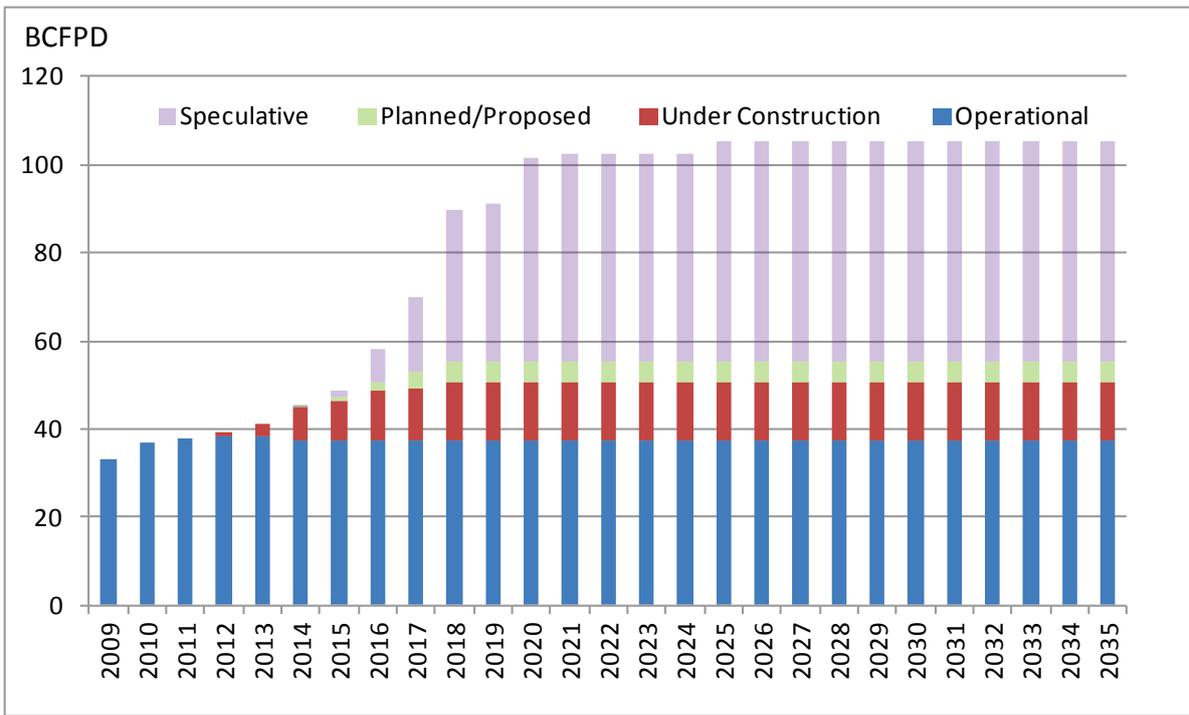


Figure 5: Global LNG Planned Liquefaction Capacity¹²
Source: CERI

Plans to construct new LNG regasification terminals suggest that a growing proportion of natural gas consumption will be met with imported LNG, particularly in developing countries without significant natural gas pipeline infrastructure. With the exception of North America, LNG demand is increasing rapidly across all regions of the world. If all proposed projects are constructed, global LNG regasification capacity will reach 137.7 BCFPD¹³ by 2020.

Figure 6 below displays the global LNG regasification capacity from existing regasification terminals, projects that are under construction, as well as planned and speculative LNG regasification projects that have been announced.

¹² Natural gas liquefaction projects are being planned across all regions of the world, and could increase the world’s total liquefaction capacity to 105.1 BCFPD if all projects were constructed. But not all planned or speculative projects will proceed to the construction phase. New natural gas discoveries are creating opportunities for countries to export excess natural gas, in the form of LNG, to markets that value LNG the most. The ability to secure long-term sales and purchase agreements with LNG importers and to obtain the financing necessary to construct the liquefaction facilities will be crucial for LNG developers.

¹³ CERI

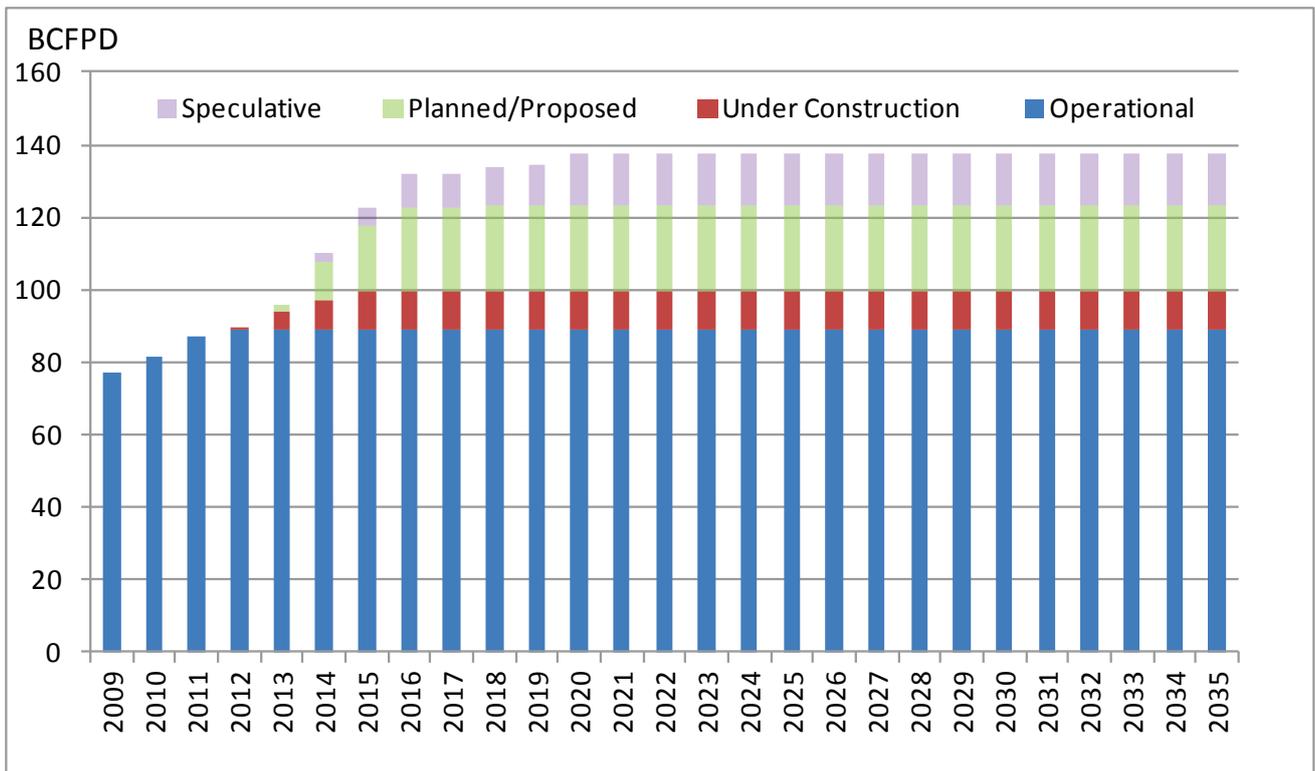


Figure 6: Global LNG Regasification Capacity, 2009-2035¹⁴
 Source: CERl

Conclusion: There is a big gap between liquefaction and regasification terminals. Thus implying the potential for liquefaction terminals targeting the huge Asia Pacific market.

GLOBAL LNG PRODUCERS TARGETING ASIA-PACIFIC MARKETS

Historically global LNG production can be classified into three time clusters-

- Class 1: 1962-1996 (Malaysia and Indonesia)
- Class 2: 1997-2012 (Qatar, Malaysia and Indonesia)ⁱ

Presently there are 18¹⁵ exporting countries and 25¹⁶ importing countries spread worldwide, with many more aspiring to enter the market. According to BP Statistical review 2012, global natural gas production has increased by 3.1%. The US (+ 7.7%) recorded the largest volumetric increase despite lower gas prices, output also increased in Qatar (+25.8 %), Russia (+3.1%) and Turkmenistan (+40.6%), more than offsetting declines in Libya and UK. LNG Shipments grew by 10.1% with Qatar (+34.8%) accounting for virtually all (87.7%) of the increase. Among LNG importers, the largest volumetric growth was in Japan and the UK. LNG now accounts for 32.3 % of global gas trade.¹⁷

¹⁴ If all proposed projects are constructed, global LNG regasification capacity will reach 137.7 BCFPD by 2020

¹⁵ BG Group- <http://www.bg-group.com/InvestorRelations/Presentations/Pages/Global-LNG-Market.aspx>

¹⁶ ibid

¹⁷ BP Statistical Review 2012.

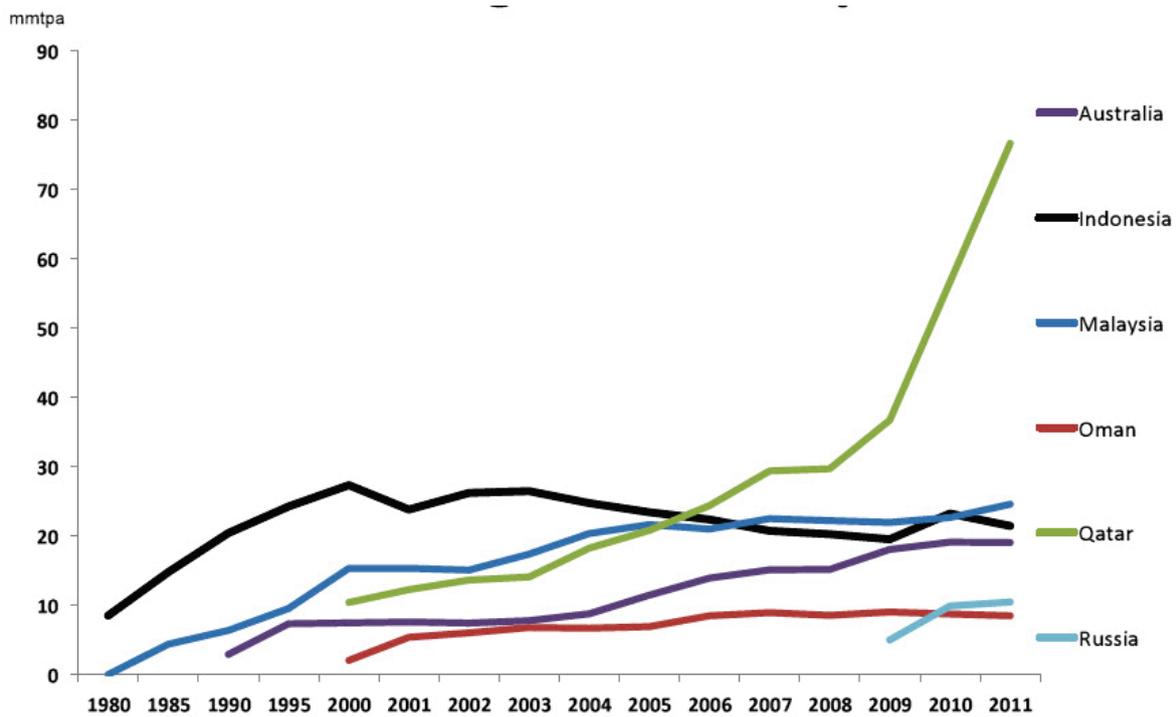


Figure 7: Global LNG Suppliers
Source: FACTS Global Energy

- Class 3: 2013-2030 (Qatar, Australia and North America)

According to PIRA, producers in the third class will control 52.4% of global LNG production by 2030, rising from 9.3% in 2010.¹⁸ This clearly indicates the opportunity for a stable country like Canadaⁱⁱ that doesn't have a single existing LNG export terminal as of now. The figure below indicates the

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The next section will explore the various LNG project, presently being considered that are targeting the Asian markets.

CANADIAN PROJECTS

Key Goal: The goal for greenfield LNG projects to go ahead from the Canadian West Coast would be to find the netback price that offers the highest returns to its Canadian gas price as well as being competitively priced with respect to its competitors.

In North America, due to the shale gas, the prices are low compared to the rest of the world. In the current context of a relative surplus, exports of gas to Asian markets might help Western Canadian gas to get a premium over its existing regional prices... Canadian producers see the Western Canadian basins as competitive enough to challenge the LNG from the Middle East and Australia. It is envisaged that the transport costs from BC to the Asian markets would be quite similar to that of the Middle East; however the price of gas at source would be more than the Middle East. BC LNG projects would be more competitive than the ones from Australia or Russia (Sakhalin).²⁰

¹⁸ PIRA – LNG Special Report (Dec 2012)

¹⁹ BP Statistical Review 2012.

²⁰ PIRA – Kitimat and the LNG Tipping Point (Nov 11, 2009)

Despite challenges, proximity, low political risk and available resources will enable Canada to maintain a key role in supplying the Asian market.

The potential supply sources for the Canadian LNG projects could come from the following sources:

Table 1:

Supply Basin	Resource Potential	Current Production	Quality of Gas
Horn River	~ 90 Tcf	~ 0.5 Bcfpd	Dry gas and 10% CO ₂ .
Liard Basin	~ 70 Tcf		Predominantly dry gas
Montney	Around 120 Tcf		Gas condensate window – potential for liquids, and low CO ₂ content.
Cordova Embayment	New resource		
Duvernay	New resource		Very promising liquids rich opportunity

The table below lists some of the potential LNG projects from Canada:

Table 2:

Project, location, developers	Capacity (bcfd)	Notes	Est. Capital Cost
Kitimat LNG, Kitimat - Chevron Canada and Apache	1.4	Received export license from NEB; Actively marketing oil-indexed LNG; No firm sales agreements announced to date; The partners have substantial positions in Horn River and Montney.	\$ CDN4.5 billion (Phase 1 + 2)
BC LNG Cooperative LLC, Douglas Channel Energy Project, Kitimat - (LNG Partners and Haisla First Nations)	0.1 to 0.23	Received export license from NEB; Cooperative model, offering one cargo per month; Invited separate bids for supply of feedgas and purchase of LNG; Key project sponsor (LNG Partners) understood to be in financial trouble	\$ CDN0.4 – 0.6 billion
LNG Canada, Kitimat - (Shell, PetroChina, KOGAS, Mitsubishi)	3.3 (4 trains)	Applied for export license in July 2012; All the partners (Shell, PetroChina, KOGAS, and Mitsubishi) are participating in Upstream JVs, one or more of which could be used to source feedgas; 1.5 bcfpd proposed initially. Shell expected to include share of off-take in its global LNG portfolio, other partners expected to off-take equity LNG for respective markets	\$ CDN12.35 billion

PETRONAS project, Prince Rupert- Petronas	1	Not yet applied for export license; Recently acquired the E&P company, Progress, which had one of the largest acreage positions in Montney; PETRONAS targeting legacy customers in Asia and home country demand in Malaysia	\$ CDN5.5 billion
BG project, Prince Rupert - BG	TBA	Not yet applied for export license; BG likely to market most of the production as part of its global LNG portfolio	TBD
Nexen- Impex LNG Project	TBA	Not yet applied for export license; Nexen was recently by CNOOC- Chinese National Oil Co:	TBD ²¹

KITIMAT LNG

The Kitimat LNG Terminal project is a proposed natural gas export (liquefaction) facility located at Bish Cove near the Port of Kitimat, BC. This location was selected for its deep, active channel for shipping, and access to existing pipeline infrastructure in the Western Canadian Sedimentary Basin.

Currently the project is being commissioned for a 2-train facility with each train capable of producing 5MMTPA (0.7 Bcf/d) of LNG for a combined total of 10MMTPA (1.4 Bcf/d). The current plan is for the trains to be installed in 2 phases with Phase 1 in 2015 and Phase 2 in 2017-18. However, the project owners have stated a goal to secure long term arrangements for 80% of the capacity before proceeding²².

According to a recent Encana presentation²³, negotiations are underway with potentially up to 6 buyers. These deals are expected to be completed in 2012 in conjunction with FEED completion and should be crude oil linked (through Japan Custom Cleared pricing). The volumes being negotiated would support development of a 2 train facility.

Natural gas feedstock will be transported to the LNG terminal as follows:

- BC sourced supply will be collected on Spectra's Raw Gas Transmission (RGT) gathering system and delivered to the Fort Nelson Processing Plant (FNPP) for processing. Processed gas would then be booked onto Spectra's T-North Mainline and delivered to Station 2 (STN2).
- AB based supply will be delivered to Station 2 (STN2) from the NOVA Gas Transmission Ltd (NGTL) system through Spectra's T-North.
- Gas available to STN2 will then be delivered to STN4A (Summit Lake) via Spectra T-South mainline.
- From STN4A (the proposed interconnect with Pacific Trails Pipeline) the gas will be transferred to the Kitimat LNG Terminal via Pacific Trails Pipeline.

²¹ Modified from Wood Mackenzie- North America Gas Long Term View: Fall 2012

²² Encana. "Encana Corporation – Global LNG Summit". March 29, 2012.

["http://www.encana.com/pdf/investors/presentations-events/global-lng-summit.pdf"](http://www.encana.com/pdf/investors/presentations-events/global-lng-summit.pdf)

²³ Encana. "Encana Corporation – Global LNG Summit". March 29, 2012.

["http://www.encana.com/pdf/investors/presentations-events/global-lng-summit.pdf"](http://www.encana.com/pdf/investors/presentations-events/global-lng-summit.pdf)

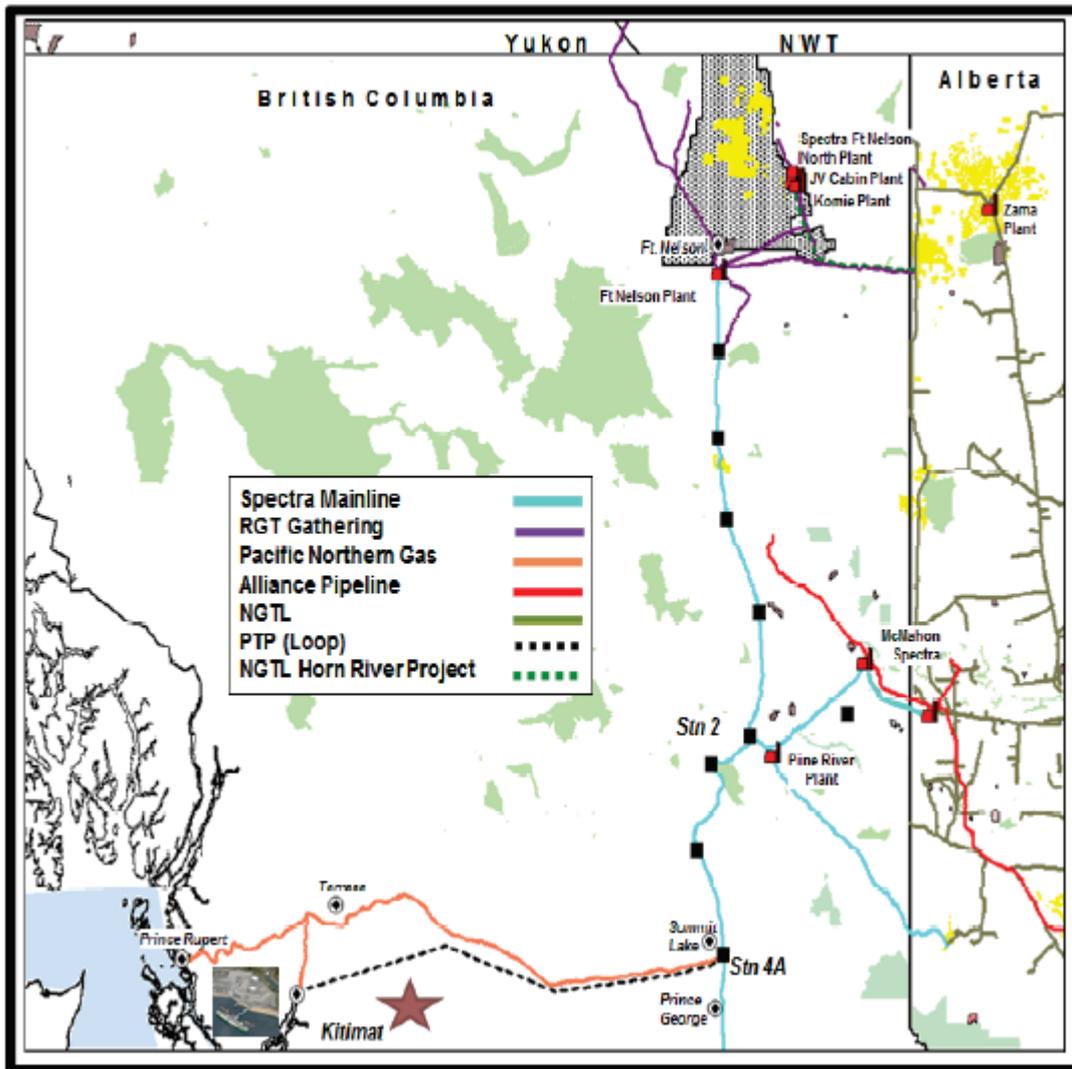


Figure 8: Pipeline infrastructure for Kitimat LNG

Source: NEB. "Kitimat LNG NEB Export Licence Application - Appendix 5 - Exhibit A".

The preliminary cost estimate for Phase 1 is \$ CDN3 billion while Phase 2 is estimated at \$ CDN1.5 billion. Ownership of the LNG project which includes the LNG plant, the Pacific trails pipeline is split 50% - Apache Canada and Chevron Canada. Apache, an experienced producer of unconventional oil and gas resources, will operate the new joint venture's development of 220,000 gross acres in the Horn River Basin and 424,000 gross acres in the Liard Basin. Chevron will purchase a 50 percent interest in undeveloped upstream assets in the Liard Basin from Apache and other Horn River assets from Encana, EOG and Apache.²⁴ Due to the relatively high cost of developing unconventional gas resources in Alberta and British Columbia, it is likely that the price of LNG sold from the facility would be linked to Japan's customs-cleared crude oil price. LNG buyers may be offered an equity stake in the liquefaction project as an incentive to sign LNG sales and purchase agreements. A final investment decision will be made once LNG supply contracts have been secured and the Front-end Engineering and Design (FEED) study is completed. The first LNG processing train could commence operations in 2017.

²⁴ Kitimat LNG Facility.

http://mediacenter.kitimatlngfacility.com/Mediacenter/view_press_release.aspx?PressRelease.ItemID=2831

Project Summary Table

Table 3:

Project	Est. Capital Cost	Location	Capacity	Stakeholders	Related Infrastructure	Potential Feedstock Sources
Kitimat LNG	\$ CDN4.5 billion (Phase 1 + 2)	Kitimat, BC	1.34 Bcf/d (2 trains)	50% - Apache Canada 50% - Chevron	<p>Supply delivery to STN2 via:</p> <ul style="list-style-type: none"> • BC gas = Spectra RGT System • AB gas = NOVA Gas Transmission Ltd (NGTL) system <p>Transport of gas from STN2 to STN4 - Spectra Mainline (T-South)</p> <p>Transport of gas from STN4 to Kitimat LNG facility - Pacific Trails Pipeline</p>	Horn River Montney AB sources

Timeline²⁵

- Q4 2015/Q1 2016 – first LNG exports expected
- 2013-2015 - Construction
- Dec 2012 – Chevron buys 50% stake in Kitimat LNG terminal
- 2012
 - FEED study complete
 - Commercial contracts in place
 - Final Investment Decision (FID) expected
 - Pipeline route clearing
 - Facility construction ramps up
- October 2011 – Canada’s National Energy Board grants Kitimat LNG a 20 year Export Licence to serve international markets.
- July 2011 – Kitimat LNG purchases Eurocan industrial site
- March 2011 – Kitimat LNG partners Apache Corporation and EOG Resources Inc. announce that Encana Corporation has agreed to acquire a 30-per cent, working-interest ownership
- March 2011 –Kitimat LNG partners acquire Pacific Trail Pipelines
- March 2011 – Kitimat LNG awards Front End Engineering and Design (FEED) contract to KBR
- March 2011 – Historic ceremonial signing with Haisla Nation and Kitimat LNG at Kitimaat Village
- December 2010 – KM LNG files Canadian federal export license application
- December 2010 – FEED commences
- December 2010 – EOG closes agreement on purchase of 49 per cent of Kitimat LNG project

²⁵ Kitimat LNG Facility website <http://www.kitimatlngfacility.com/>. Accessed July 6, 2012.

- November 2010 – Documents fully executed for Uplands and Foreshore leases with related agreements
- November 2010 – Haisla Nation votes overwhelmingly to approve land lease
- May 2010 – EOG Resources Canada Inc. (EOG) signs pre-acquisition agreement to purchase remaining 49 per cent of LNG project
- January 2010 – KM LNG through its managing partner Apache Canada Ltd. purchased 51 per cent of the project and becomes operator
- January 2009 – Canadian provincial environmental assessment approval
- December 2008 – Canadian federal environmental assessment approval
- August 18 2004 – Kitimat LNG applied to the British Columbia Environmental Assessment Office (BCEAO) for a provincial environmental assessment (EA) certificate for an LNG import, regasification and send-out terminal.

LNG CANADA PROJECT (ROYAL DUTCH SHELL PLC)

On May 15, 2012 Shell Canada announced plans to develop a LNG export facility near Kitimat, BC. The LNG Canada Project will initially consist of 2 trains each with the capacity to produce 6MMTPA (0.80 Bcf/d) for a combined total of 12MMTPA (1.6 Bcf/d). The facility will be designed with the ability to expand capacity to 4 trains with the capacity to produce a combined total of 24 MMTPA (3.2 Bcf/d)²⁶.

The total project costs have been estimated around C\$12.35 billion²⁷. Partners in the project for the first 2 trains are 40% - Shell (www.shell.ca), 20% - Mitsubishi Corporation (<http://www.mitsubishicorp.com/jp/en/bg/energy/>), 20% - Korea Gas Corp (http://www.kogas.or.kr/kogas_eng/html/main/main.jsp), and 20% - PetroChina Company Ltd. (<http://www.petrochina.com.cn/ptr/>). As per their application, ownership structure of the last 2 trains has not yet been determined.

The facility will connect to supply by way of the C\$4 billion proposed Coastal GasLink project²⁸. The Coastal GasLink project would receive supply from the Montney, Horn River, and Cordova basins at a receipt point near Dawson Creek, BC. Initial pipeline capacity is estimated at 1.7 Bcf/d, expandable, with an estimated in-service date of 2019-2020.

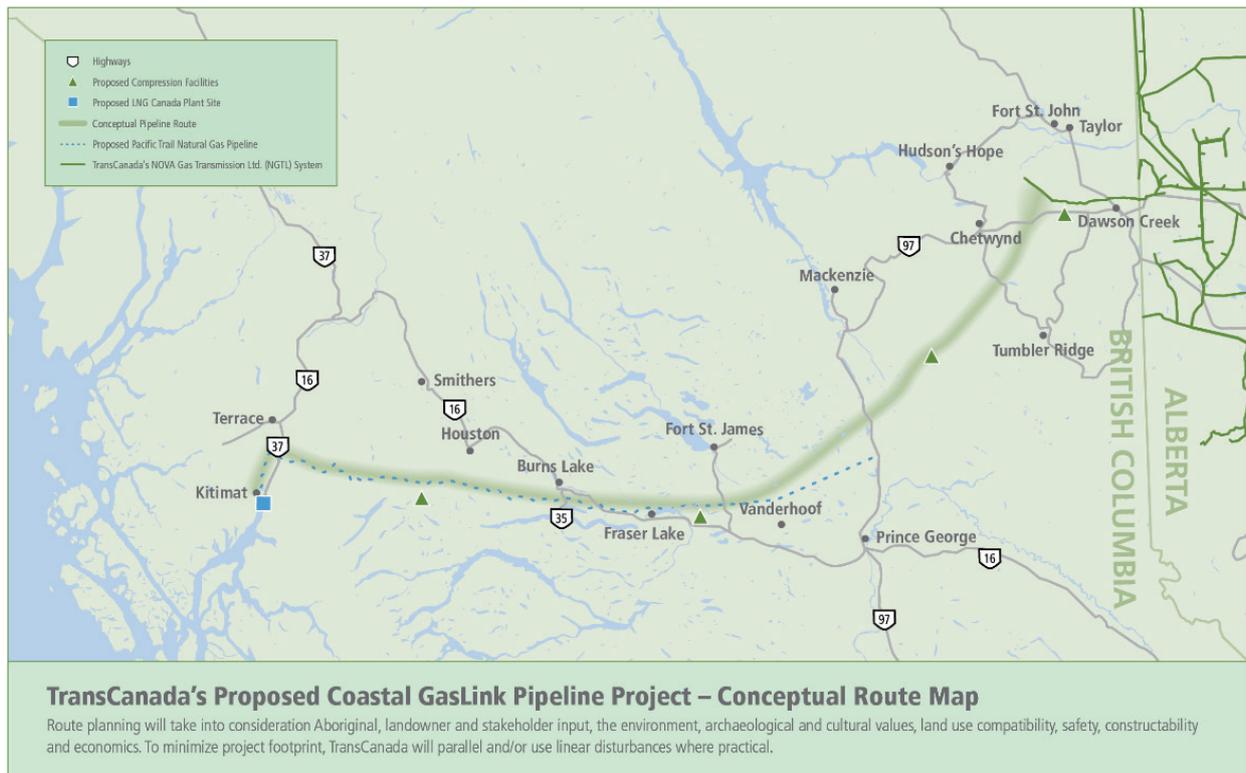
²⁶ Taken from project NEB export license application. <https://www.neb-one.gc.ca/ll-eng/livelink.exe?func=ll&objId=834774&objAction=browse&sort=name>

²⁷ DOB. "LNG Export Race is on in Canada". April 23, 2012.

Western Investor. "Shell Canada backs huge LNG plant in Kitimat". May 23, 2012.

<http://www.westerninvestor.com/index.php/news/bc/844-shell-backs-huge-lng-plant-at-kitimat->

²⁸ TransCanada. "TransCanada Selected by Shell and Partners to Develop Multi-Billion Dollar Natural Gas Pipeline to Canada's West Coast". June 5, 2012. <http://www.transcanada.com/6054.html>



June 2012

Figure 9: Pipeline Infrastructure for Canadian LNG project

Source: TransCanada. "Coastal Gas Link Pipeline Project – Conceptual Route Map". June 2012.
http://transcanada.com/docs/Key_Projects/cgp-conceptual-route-map.jpg

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Table 4:

Project	Est. Capital Cost	Location	Capacity	Stakeholders	Related Infrastructure	Potential Feedstock Sources
LNG Canada (Royal Dutch Shell Plc)	\$ CDN12.35 billion	Kitimat, BC (built on the mothballed Methanex site)	3.2 Bcf/d (4 trains)	First 2 trains: 40% - Shell 20% - Mitsubishi 20% - Korea Gas (KOGAS) 20% - PetroChina	Coastal GasLink Project	Montney Horn River Cordova AB sources

Timeline

2020 Q3 - Liquefaction train #4 start-up

2020 Q1 - Liquefaction train #3 start-up (at earliest)

2019 Q3 - Liquefaction train #2 start-up

2019 Q1 – Liquefaction train #1 start-up

Jul 27 2012²⁹ – Project stakeholders apply to the NEB for an export license. The export application is for a license authorizing the export of up to 24 MMTPA (3.2 Bcf/d) for a 25 year term.

²⁹ Reuters. "Shell, partners file for Canada LNG export license". July 27, 2012.
<http://www.reuters.com/article/2012/07/27/shell-canada-lng-idUSL2E8IRCC720120727>
 NEB export license application. <https://www.neb-one.gc.ca/ll-eng/livlink.exe?func=ll&objId=834774&objAction=browse&sort=name>

May 15 2012 – Consultation with First Nations and affected local communities begins.

BC LNG EXPORT COOPERATIVE LLC

The proposed BC LNG Export Cooperative is a \$400-600 million³⁰ small scale barge-based liquefaction plant located on the west bank of the Douglas Channel approximately 10 km southwest of Kitimat, BC. With a barge-based project the inlet gas treating, liquefaction, utilities and support systems are built on an ocean-going barge which is then towed and moored to the site.

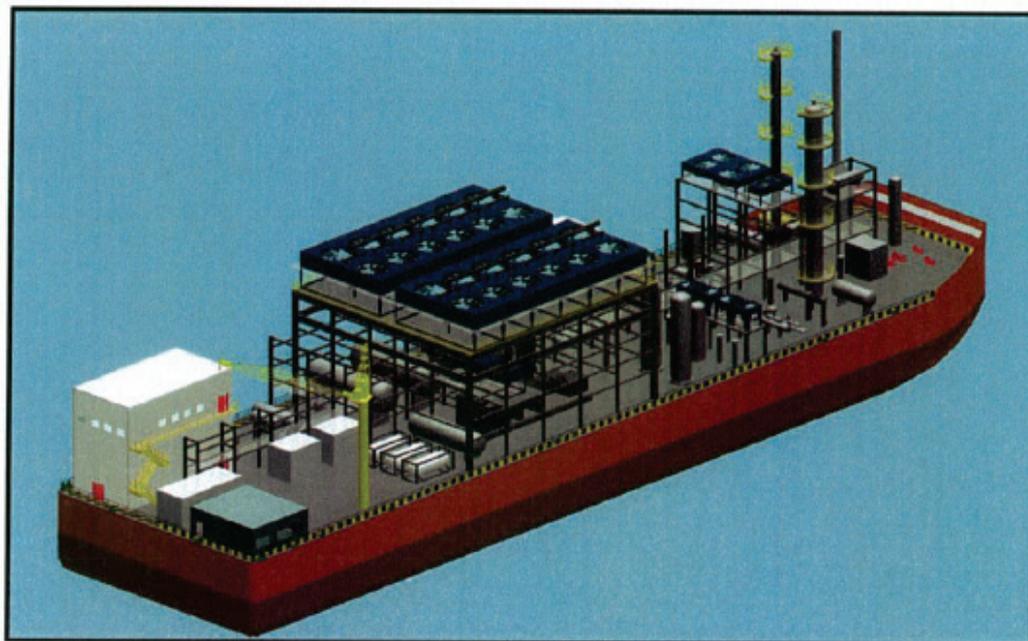


Figure 10: Schematic of Barge-based LNG production vessel

Source: Stantec Consulting. "Douglas Channel Small Scale LNG Project – Project Description". December 2010.

The liquefaction plant will be designed with 2 trains each capable of converting up to 0.90 MTPA (0.125 Bcf/d) for a combined total of 1.80 MTPA (0.230 Bcf/d). The first train is intended to be completed in Q4 of 2013 or early 2014.

The project will obtain feedstock from producers/marketers with supply in Northeastern BC and portions of the Western Canadian Sedimentary Basin (WCSB), but primarily from Northeast BC.

³⁰ Haisla First Nations. "Economic Development – Projects - BCLNG". Accessed July 9 2012. <http://haisla.ca/economic-development/projects/bclng/>



Figure 11: BC LNG Infrastructure

Source: Douglas Channel Energy Partnership. "Project Description – Project Images". Accessed July 9 2012.

Ownership of the LNG project is split 50/50 between LNG Partners LLC (<http://www.lngpartners.com/index.html>) and HN DC LNG Limited Partnership (<http://www.haislabusinessoperations.ca/>).

Project Summary Table

Table 5:

Project	Est. Capital Cost	Location	Capacity	Stakeholders	Related Infrastructure	Potential Feedstock Sources
BC LNG Export Cooperative LLC	\$ CDN0.4 – 0.6 billion	Kitimat, BC	0.230 Bcf/d (2 trains)	50% - LNG Partners, LLC 50% - HN DC Limited Partnership (owned by Haisla nation)	0.080 Bcf/d - Pacific Northern Gas Ltd. - KSL Looping Project 0.013 Bcf/d – Pacific Northern Gas Ltd. – existing Remainder – negotiated on Pacific Trails Pipeline	Horn River Montney AB sources

Timeline³¹

- Q4 2013 – Q1 2014 – Initial facility commercial operations
- Q1 2012 - Q4 2013 – Design, construction, and commissioning
- February 2, 2012 – NEB grants project 20-year license to export LNG
- Q4 2011 – Environmental assessment and permitting

³¹ Taken from project website <http://douglaschannelenergy.com/project-description.htm>. Accessed July 9, 2012.

- Q4 2011 – FEED engineering activity
- Q3 2011 – Key contracts and agreements
- March 8, 2011 – BC LNG Export Co-operative LLC files application with NEB for a natural gas export license

PACIFIC NORTHWEST LNG PROJECT

On August 2, 2011 Petronas closed a transaction to purchase a 50% working interest in Progress' Montney assets (Altares, Lily, and Kahta properties) and noted an opportunity to also JV in a LNG project (Petronas 80% / Progress 20%)³². On June 28, 2012 Petronas later increased their ownership to 100% (both supply and facility) by acquiring Progress Energy for \$ CDN5.4 billion³³.

The development of the LNG export facility will be lead Petronas but will be jointly marketed utilizing Petronas' existing network of LNG customers. The Prince Rupert based (on Lelu Island³⁴) facility would consist of 2 trains each with the capacity to produce 3.7MMTPA (0.5 Bcf/d) for a combined total of 7.4MMTPA (1.0 Bcf/d)³⁵. A feasibility study for the Petronas LNG terminal, located on Lelu Island in northern British Columbia, is expected to be completed by August 2013. If a final investment decision is reached by the fourth quarter of 2013, the facility could begin exporting approximately 1 BCFPD to LNG buyers in Japan, South Korea, and Taiwan by 2018.

Petronas has tapped TransCanada to build a pipeline with a potential capacity upto 3.6 bcfpd. This proposed pipeline will transport natural gas primarily from the North Montney gas-producing region near Fort St. John, British Columbia (B.C.) to the recently-announced Pacific Northwest LNG export facility in Port Edward near Prince Rupert, B.C. TransCanada proposes to extend its existing NOVA Gas Transmission Ltd. (NGTL) system in northeast B.C. to connect both to the Prince Rupert Gas Transmission project and to additional North Montney gas supply from Progress and other parties. This new infrastructure will allow the Pacific Northwest LNG export facility to access both the abundant North Montney supplies as well as other Western Canada Sedimentary Basin (WCSB) gas supply through the NOVA Inventory Transfer (NIT) trading hub and the extensive existing NGTL pipeline network.

³² Progress Energy. "Progress Energy announces the closing of its strategic partnership with Petronas". August 2, 2011. <http://www.progressenergy.com/progress-energy-announces-the-closing-of-its-strategic-partnership-with-petronas>

³³ Peters & Co. Limited. "Acquisition by Petronas". June 28, 2012.

³⁴ Progress Energy. "Petronas to acquire Progress Energy". June 28, 2012. <http://www.progressenergy.com/petronas-to-acquire-progress-energy>

³⁵ Financial Post. "Canada's natural gas dreams closer to reality after Petronas moves". Jun 28, 2012. <http://business.financialpost.com/2012/06/28/canadas-natural-gas-dreams-closer-to-reality-after-petronas-moves/>
Invest in Northwest BC. "Petronas LNG". Accessed July 10, 2012. <http://investnorthwestbc.ca/major-projects-and-investment-opportunities/map-view/prince-rupert/petronas-lng>

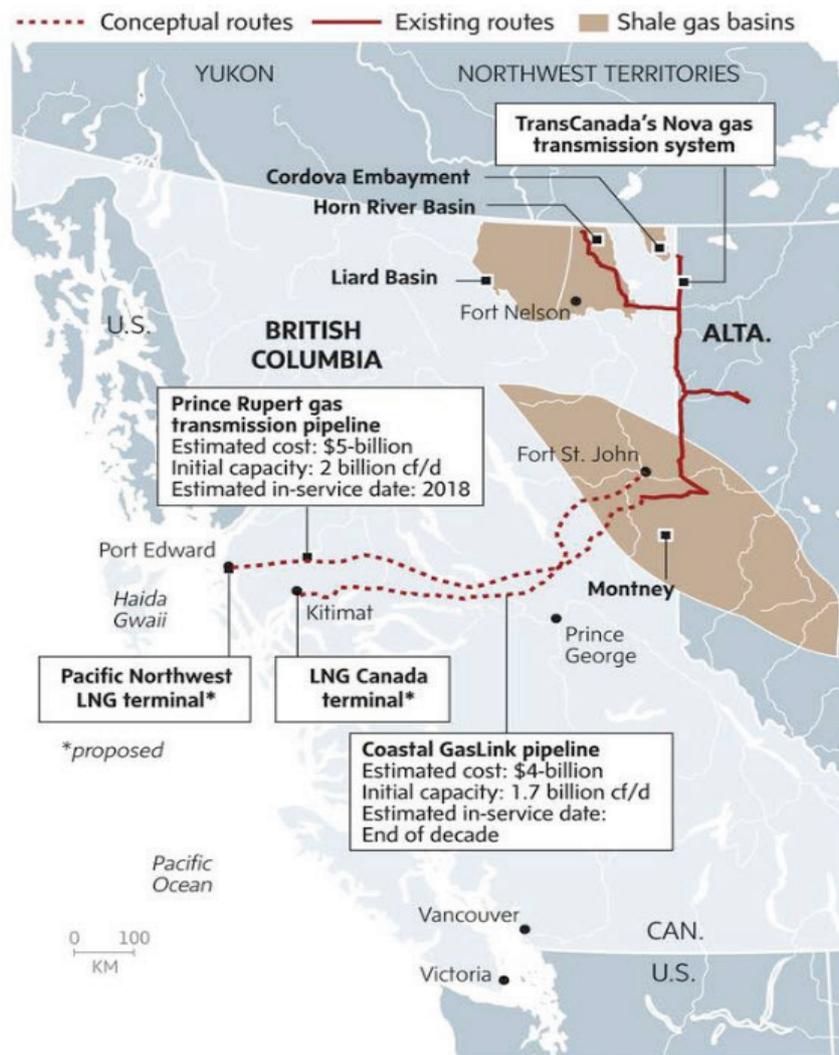


Figure 12: Pacific North-West LNG Infrastructure

Source: Invest Northwest BC. "Petronas LNG". Accessed July 10, 2012. <http://investnorthwestbc.ca/major-projects-and-investment-opportunities/map-view/prince-rupert/petronas-lng>

Project Summary Table

Table 6:

Project	Est. Capital Cost	Location	Capacity	Stakeholders	Related Infrastructure	Potential Feedstock Sources
Petronas LNG Project	\$ CDN5.5 billion	Prince Rupert (on Lelu Island)	1 Bcf/d (2 trains)	Petronas	TBD	Montney

Timeline

- 2018 – First LNG shipments
- Jan 09, 2013 - TransCanada Selected to Develop \$6 Billion in Natural Gas Infrastructure to Prince Rupert, British Columbia for the Petronas LNG project
- Q3 or Q4 2013- Submit Environment Assessment
- Q3 2014 – Issue Initial Construction Permits
- Q4 2014 – Final Investment Decision³⁶
- End of 2014 , early 2015 – Construction begins

³⁶ Pacific North West LNG- <http://pacificnorthwestlng.com/project-timeline/>

- Q 4 2018 – LNG shipments begin
- Q3 2012 – Completion of Feasibility study and commencement of pre-FEED phase³⁷
- November 2011 – Feasibility study commenced
- June 28, 2011 – Petronas announces site selection (Prince Rupert) and signing of a feasibility assessment agreement with the Prince Rupert Port Authority.
- June 2, 2011 – Announcement of potential LNG project

BG GROUP

In February 2012, the UK based BG Group confirmed it is assessing the feasibility of an LNG export facility in the Prince Rupert area³⁸. In addition to commencing feasibility studies, BG Group entered into an agreement with the Prince Rupert Port Authority to secure access to a 200-acre section of land on the Ridley industrial development site³⁹.

Spectra and BG of Reading, England, will be 50-50 owners in the pipeline. The pipeline, which remains conceptual and would take years to permit and build, would connect the gas fields in northeast British Columbia with Prince Rupert, where BG has gained access to port land it believes to be suitable for construction of an export terminal for LNG. The 850-kilometre line would be built with a capacity of 4.2 billion cubic feet per day. Few details have been disclosed regarding the potential LNG facility.



Figure 13: BG’s Canadian LNG Infrastructure Map

Source: Spectra, BG, plan gas pipeline across northern B.C.

<http://www.cbc.ca/news/business/story/2012/09/10/spectra-bg-gas-pipeline.html>

³⁷ DOB. “Canadian LNG Positioned to Succeed Progress Energy”. May 3, 2012.

³⁸ DOB. “BG Group Assessing Feasibility for LNG Plant in Prince Rupert Area”. February 8, 2012.

³⁹ Globe and Mail. “UK firm joins race to export gas from BC”. February 7, 2012.

Project Summary Table

Table 7:

Project	Est. Capital Cost	Location	Capacity	Stakeholders	Related Infrastructure	Potential Feedstock Sources
BG Group	TBD	Prince Rupert, BC	BG group is considering a potential capacity of 4.2 bcf a day gas pipeline to feed its LNG project.	100% - BG Group Plc	TBD	TBD

Timeline

February 2012: BG Group confirmed in 2012 that it had secured access to a 200-acre section of coastal land on the Ridley industrial development site, owned by the Prince Rupert Port Authority, to assess the viability of an LNG terminal there. The port normally provides companies 12 to 24 months to assess whether they can make a project work.

NEXEN/INPEX CORPORATION

On November 29, 2011 Nexen announced a sale and joint venture partnership for their assets in northeast BC (Horn River, Cordova, and Laird basins). The agreement created a partnership with INPEX corporation of Japan where INPEX received a 40% working interest and Nexen remains the operator. The announcement also indicated that “the parties will jointly investigate the feasibility of a potential downstream project including LNG exports”⁴⁰.

Since the announcement few details have been disclosed regarding the potential LNG facility.

Project Summary Table

Table 8:

Project	Est. Capital Cost	Location	Capacity	Stakeholders	Related Infrastructure	Potential Feedstock Sources
Nexen/Inpex Corporation	TBD	TBD	TBD	Nexen INPEX corporation	TBD	Horn River Cordova Laird AB sources

Timeline

November 29, 2011: Joint feasibility study of potential LNG project commenced between Nexen and Inpex.

In July 2012, Nexen agreed for a take over by Beijing-based China National Offshore Oil Corp. for \$15 billion, a deal expected to close in the fourth quarter provided that shareholders agree at a vote in September and it passes review under federal government foreign investment rules.

In August 2012, Globe and Mail reported that Inpex, now own 40 per cent of Nexen’s shale gas assets in the Horn River, Cordova and Liard basins of northeast British Columbia. Nexen remains the operator.

⁴⁰ Nexen Inc. “News Release – Nexen Announces Sale and Joint Venture Partnership for Northeast British Columbia Shale Gas Assets”. November 29, 2011.

http://www.nexeninc.com/en/AboutUs/MediaCentre/NewsReleases/News/Release.aspx?year=2011&release_id=117759

AUSTRALIAN LNG PROJECTS

In 2011 Australia was the fourth-largest LNG exporter by volume – behind Qatar, Malaysia and Indonesia – accounting for 7.9% of global LNG exports. Japan accounted for 73.4% of Australia’s LNG exports and China for 19.3% in that year. The remainder was exported to South Korea, Taiwan, India, and the Middle East.⁴¹

EIA estimates Australian shale gas reserves to be close to 400 Trillion Cubic Feet and around 135 Tcf in proved reserves. With a lot of interest in shale gas recently, Australia is all set to overtake Qatar to become the largest LNG exporter in future. Australia’s large natural gas resource base and close proximity to traditional and emerging LNG markets, has attracted substantial investments from international oil and gas companies, as well as potential LNG buyers over the past several years. Australia is expected to be responsible for the majority of incremental LNG supply additions over the short- to medium-term. With over \$180 billion invested in the seven liquefaction projects in the construction phase, including three coal bed methane-based LNG projects and one offshore floating terminal, Australia’s natural gas liquefaction capacity could exceed that of Qatar by the end of 2017.⁴² Ignoring projects that have not yet been sanctioned, and assuming that further construction delays do not occur, Australia’s LNG export capacity will increase from 3.3 BCFPD in 2012, to approximately 11.4 BCFPD in 2018.

Australia has a total approved LNG capacity of 71.7 Mtpa (~9.6 BCFPD), including one liquefaction facility that is proposing to process and export natural gas from the Greater Sunrise joint development area with East Timor. If all of the announced projects move forward, the country could see its export capacity more than quadruple, to 17.2 BCFPD, by the end of 2020 and as much as 130 Mtpa⁴³ by 2035. This scenario is highly unlikely due to a number of significant challenges facing Australia’s LNG industry. The value of Australia’s LNG projects according to IHS CERA totals US \$ 174 billion, this is due to the high volumes combined with the high capital costs involved. This includes a shortage of skilled labour, which is contributing to construction delays and cost overruns, competing projects that are driving up the cost of materials, concerns over the cost and availability of CBM feedstock gas supplies, higher operating costs associated with Australia’s new cap-and-trade scheme, and new taxes (July 1, 2012).

Table : 9

Natural gas (incl. LNG feedstock)	Million cubic metres
Western Australia	31,857
Australia	51,404
Western Australia share	62%

<http://www.dmp.wa.gov.au/>

Table 10 below provides a summary of the proposed LNG projects in Australia

⁴¹ OGFJ- EIU: Australia’s coming LNG boom (Aug 08 2012) - <http://www.ogfi.com/articles/2012/08/australias-coming-lng-boom.html>

⁴² Australia’s actual LNG output will not surpass Qatar’s until the following year, as additional time is needed for LNG production to ramp up to full capacity.

⁴³ Platts – Australian LNG sector could produce 130 Mtpa by 2035 (Accessed on Nov 30 2011)

http://www.platts.com/RSSFeedDetailedNews/RSSFeed/NaturalGas/7216637?goback=%2Egmp_2810863%2Egde_2810863_member_181641996

Table 10:

Project	Est. Capital Cost (b US\$)	Status	Capacity (Trains)	Start Date	Stakeholders
Queensland Curtis LNG (QCLNG)	20.4	Current Construction	8.5 Mtpa (2) ⁴⁴	2013 (late)	Queensland Gas Company QGC (a BG group company)
Gladstone LNG (GLNG)	16.0	Current Construction	7.8 Mtpa (2) ⁴⁵	2014	Santos Ltd, Petronas, Kogas and Total
Australia Pacific LNG (APLNG)	20.0	Current Construction	8.6 Mtpa (2) ⁴⁶	2015	Origin, ConocoPhillips and Sinopec
Arrow LNG ⁴⁷	15+	Proposed project	9.2 Mtpa (2) ⁴⁸		Shell and PetroChina
Gladstone LNG ⁴⁹ Fishermans Landing			1.5 to 3 Mtpa ⁵⁰	2014	LNG Limited and Huanqiu Contracting and Engineering Corporations HQCEC (a wholly owned subsidiary of China national Petroleum Corporation)
Sun LNG	No Data		0.5 to 1 Mtpa ⁵¹		Sojitz Corporation
Impel – Southern Cross	3-5		0.7 to 1.3 Mtpa	2013	Southern Cross LNG
Pluto -1	14.9		4.3 Mtpa (1)	March 2012	Woodside 90% Kansai Elec. 5% Tokyo Gas 5%
Pluto - 2	10.5		4.3 Mtpa (1)	tba	Woodside 90% LNG Buyers 10%
Gorgon	37.0		15 Mtpa (3)	Late-2014	Chevron 47.33% ExxonMobil 25% Shell 25% Osaka Gas 1.25% Tokyo Gas 1% Chubu 0.417%
PNG LNG T 1-2	15.7		6.6 Mtpa (2)	Mid-2014	ExxonMobil 33.2% Oil Search 29.0% Santos 13.5% Nippon Oil 4.5% PNG Govt 16.6% PNG Landowners 2.8% Petromin 0.2%

⁴⁴ It is expected to increase production to 12 Mtpa

⁴⁵ It is expected to increase production upto 10 Mtpa

⁴⁶ Potential to increase production upto 18 Mtpa

⁴⁷ <http://www.industry.qld.gov.au/lng/projects-queensland.html>

⁴⁸ Potential to increase production upto 18 Mtpa

⁴⁹ http://www.lnglimited.com.au/IRM/content/invest_presentations.html

⁵⁰ Queensland Government. <http://www.industry.qld.gov.au/lng/projects-queensland.html>. Accessed on Nov 29, 2012

⁵¹ Queensland Government. <http://www.industry.qld.gov.au/lng/projects-queensland.html>

Wheatstone T1-2	29.0		8.9 Mtpa (2)	2016	Chevron 72.1% Apache 13.0% KUFPEC 7.0% Shell 6.4% Kyushu Electric 1.46%
Prelude FLNG	11.5		3.6 Mtpa (1)	2017	Shell 67.5% Inpex 17.5% Kogas 10% CPC (Taiwan) 5%
Ichthys	34.0	Current Construction	8.4 Mtpa (2)	2017	Inpex 74.8% Total 24.0% Osaka Gas 1.2% ⁵²
Browse	40.0		13 Mtpa (3)	2019 (est)	Woodside 31.3% BP 17.2% Chevron 17.2% BHP Billiton 10.2% Shell 9.4% MIMI (Japan) 15%
Bonaparte FLNG	5.0		2.0 Mtpa (1)	2018	GDF Suez 60% Santos 40%
Sunrise FLNG	11.5		3.6 Mtpa (1)	Tba	Woodside 33.4% ConocoPhillips 30.0% Shell 26.6% Osaka Gas 10%
Scarborough T1-2	20.0		8.6 Mtpa (2)	Tba	ExxonMobil 50% BHP Billiton 50%
Total	\$ b ⁵³				

Supply Basin	Resource Potential	Current Production	Quality of gas
Carnarvon	~ 95 Tcf		
Browse	~ 33 Tcf		
Bonaparte	~ 2 Tcf		

Source: Dept. of Industrial Resources- Room to grow your petroleum business Western Australia (Western Australia Size comparison)⁵⁴

Canada versus Australia

- LNG from Canada will be valuable for buyer portfolio diversification as the LNG industry turns heavily to Australia to meet LNG growth over the next decade. PFC Energy estimates over 50% of the growth in global LNG supply from 2011-2020 will come from Australia. This shows a very high exposure to one country, any event in Australia can impact the LNG markets especially for an LNG buyer. Hence, developing a new resource from a similar politically stable country is beneficial to the LNG buyer; this will improve the energy security for the buyer country.
- The distance to the Asian markets particularly Japan are relatively competitive with Canada taking between 6 to 8 days while Australia taking between 8-10 days.

⁵² Ichthys LNG Project - <http://gateway.icn.org.au/project/451/ichthys-lng-project>

⁵³ <http://www.industry.qld.gov.au/lng/projects-queensland.html>

⁵⁴ <http://wa.gov.au/search-results.html?cx=013143409236470047600%3Aw3rlsolxaty&q=Woodside+Petroleum+LNG+&sa=Search&cof=FORID%3A11>

- The development of many parallel projects is really challenging the Australian labor market and the costs of skilled labor are increasing. Equally challenging is contracting engineering companies.

MIDDLE EAST LNG PROJECTS

In 2011, the Middle East was the world's largest LNG producing region, accounting for 39.4 percent of the global LNG trade. More than half of the region's LNG exports were shipped to Asian markets, with Japan receiving the lion's share of the exports following the accident at the Fukushima nuclear power plant.

Annual LNG production in the Middle East increased by 28.7 percent, to 12.6 BCFPD, largely a result of new LNG supplies from Qatar. The ramp up of production at two liquefaction facilities (Ras gas 3 Train 7 and Qatargas 3 Train 6) commissioned during the previous year, along with the completion of a new facility (Qatargas 4 Train 7) in 2011, resulted in a 34.8 percent year-over-year increase in Qatar's LNG output, to 9.9 BCFPD.⁵⁵

Existing and potential LNG exporting nations in the Middle East accounted for approximately a third of the world's 7.4 TCF of proved natural gas reserves at the end of 2011. Currently, the region's natural gas liquefaction capacity amounts to 13.4 BCFPD, with nearly 77 percent of the capacity located in Qatar. Since the Qatargas and Rasgas liquefaction facilities began exporting LNG in the 1990s, the facilities have expanded to include a total of 14 liquefaction trains. Train 7 of the Qatargas 4 facility, the only global liquefaction project to commence operations in 2011, marked the end of Qatar's LNG expansion program. This brought the country's total export capacity to 10.3 BCFPD. All of the natural gas feedstock for Qatar's liquefaction facilities is transported through undersea pipelines from the world's largest non-associated natural gas field, the North Field, where a moratorium on new natural gas projects has been in place since 2005. Although no additional liquefaction projects have been announced, debottlenecking projects could increase the liquefaction capacities of existing facilities. Qatar has expressed interest in participating in foreign liquefaction projects, in order to maintain its global market share.⁵⁶

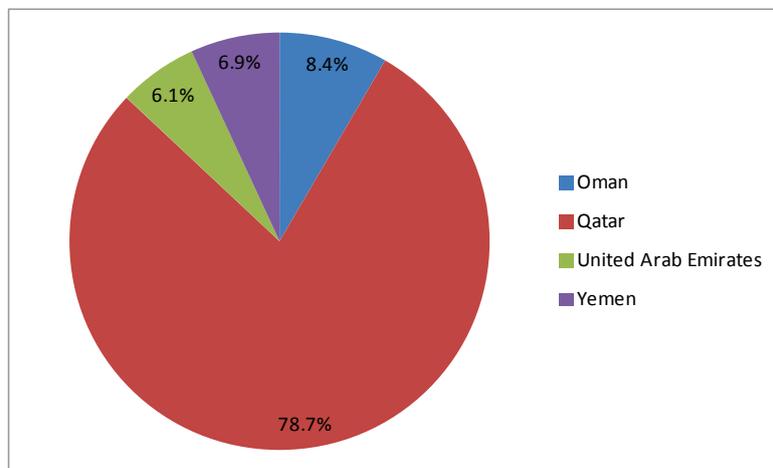


Figure 14: Middle East LNG Trade in 2011
Source: BP Statistical Review

Qatar will meet the lion's share of both the immediate and medium long-term incremental LNG requirement in Japan – having un-contracted available capacity to do so. It will likely achieve LNG price formulae significantly correlated to crude (nearing Crude Price Parity) for those supplies – hence Asian LNG prices will likely remain strong for the foreseeable future. A further consequence of this redirection will be an upward

⁵⁵ BP Statistical Review of World Energy 2012

⁵⁶ MIC Portal - http://www.micportal.com/index.php?option=com_content&view=article&id=8062:singapores-first-lng-shipment-to-come-from-qatar&catid=8:LNG/LPG&Itemid=16 – Singapore first LNG shipment to come from Qatar (Nov 30 2012)

price pressure in Europe, where the Qatari gas will need to be replaced, once spare coal capacity has been fully utilised.⁵⁷

Two new LNG exporting nations, Iran and Iraq, could increase the region’s liquefaction capacity by approximately 2 BCFPD over the next five years. The two-train Iran LNG facility, with a combined capacity of 1.4 BCFPD, is currently estimated to be 60 percent complete, and could begin exporting LNG from the South Pars Field by the fourth quarter of 2013.⁵⁸

US PROJECTS

In the United States, there are 18 projects that have applied and are seeking regulatory approval to produce LNG exports. They are approximately 27.5 Bcfpd in capacity. There is a growing consensus that among these the brownfield projects are the ones that will most likely go ahead. They won’t be as cost sensitive as the other Greenfield projects and may most likely be able to still sign contracts without the Asian oil linked pricing. For the Greenfield projects to go ahead, it is close to an absolutely necessity to find oil-linked pricing contracts. Only Cheniere’s application has been approved and is under construction.

The gas for these exports would be coming from the general grid, which makes the US LNG project quite unique and different. Below are the listing for the LNG projects (From Canadian Energy Research Institute CERI):

Table 11: Summary of Proposed LNG Export Projects in the US

Project	Capacity (BCFPD)	Start Date
Brownsville LNG Terminal	2.8	2018
Cameron LNG	1.7	2016
Corpus Christi Liquefaction Project	1.8	2018
Cove Point LNG	1.0	2017
Elba Island LNG	0.5	2020
Freeport T1-T3	1.8	2016
Gulf LNG Clean Energy Project	1.5	2020
Jordan Cove LNG	0.8	2020
Lake Charles	2.4	2018
Lavaca Bay FLSO Project	1.4	2017
Oregon LNG	1.3	2017
Sabine Pass Liquefaction Project T1-T4	2.6	2015
Valdez LNG	2.5	2025

⁵⁷ Credit Suisse - Global gas (Nov 29 2012). P.6.

⁵⁸ Zhu, Charlie, “Iran LNG delay s export start to summer 2013”, Reuters, June 8, 2012., <http://finance.yahoo.com/news/iran-lng-delays-export-start-090048519.html>,

RUSSIAN LNG

Although Russia had the world's largest proved natural gas reserves at the end of 2011, the country's LNG exports accounted for only a small portion of global LNG output, as most of its existing natural gas production takes place far from tidewater. Over the medium- to long-term however, Russia is expected to become a major exporter of LNG. Five new projects, including an expansion of the existing Sakhalin-2 facility, are in the planning phase, and could commence operations between 2015 and 2018, depending on when the final investment decisions are made. Russia is aggressively marketing LNG to potential buyers in the Asia-Pacific region, as low demand growth potential in Europe, exacerbated by the region's efforts to improve security through diversification of natural gas supply sources is expected to limit Russia's pipeline exports to the west. If all projects were to proceed without delays Russia's liquefaction capacity could increase to 6.6 BCFPD by the end of 2018.⁵⁹

In Russia, where output rises from 677 bcm (23,898.1 bcf) in 2011 to more than 850 bcm (30,005 bcf) in 2035, production continues to move gradually away from the traditional production areas in Western Siberia towards more challenging and expensive frontiers in the Arctic (mainly the Yamal peninsula, with its huge resources) and in Eastern Siberia (for export to China, which we project to begin in the early 2020s). The bulk of the increase in Russian production goes to export, but uncertainty over the pace of demand growth in Europe, Gazprom's main export market, combined with the emergence of the United States as an LNG exporter, create dilemmas for westward-oriented Russian gas export projects. This is particularly true for the major Arctic LNG projects, the Yamal LNG project proposed by Novatek and the Shtokman project proposed by Gazprom (which has been shelved, according to an August 2012 announcement by Gazprom). These projects can reach Asia-Pacific markets for part of the year via the Arctic northern route, but their reliance on European and Atlantic basin markets at other times would risk displacing a part of Russia's existing exports by pipeline (even with the anticipated extensive use of swaps). IEA (International Energy Agency) estimates that both of these projects will eventually go ahead, with Yamal LNG the first to start operation, towards 2020, on the assumption that the fiscal terms offered by the government are sufficiently attractive to underpin the project economics, and Shtokman only much later in the projection period. Ukraine has the potential to boost its domestic production, both through offshore conventional gas exploration and through development of its onshore shale gas and coalbed methane resources.⁶⁰

ASIA PACIFIC LNG MARKET

Of the total volume of natural gas traded in 2011, pipeline natural gas trade accounted for 67.7 percent (67.2 BCFPD). Although the volume of natural gas traded through international pipelines continues to exceed that of LNG across all regions, except the Asia-Pacific, where pipeline infrastructure is limited, LNG is expected to continue to account for a growing share of global natural gas consumption over time. 63.6% of global demand came from Asia. At the year end of 2011, there are 89 LNG regasification terminals in 25 countries with a 640 million tons p.a. total capacity (MTPA). As far as export terminals are concerned, there are 24 liquefaction facilities in 18 countries with a total capacity of 278 MTPA.⁶¹

Currently, East Asia's leading gas import markets are concentrated in China, Japan, and South Korea. Smaller volumes of gas are also imported by Singapore, Thailand, and Taiwan. Australia, Indonesia, and Malaysia supplied almost 65 percent of the gas imported by China, Japan, and South Korea. In Asia's developing economies there is a significant potential for massive increases in the demand for energy and with it high rates of growth in natural gas demand. The graph below clearly indicates the demand for LNG in the Asian markets.

⁵⁹ IEA- World Energy Outlook (2012).P. 137.

⁶⁰ IEA- World Energy Outlook (2012).P. 137.

⁶¹ GIIGNL – The LNG Industry of 2011.P.8.

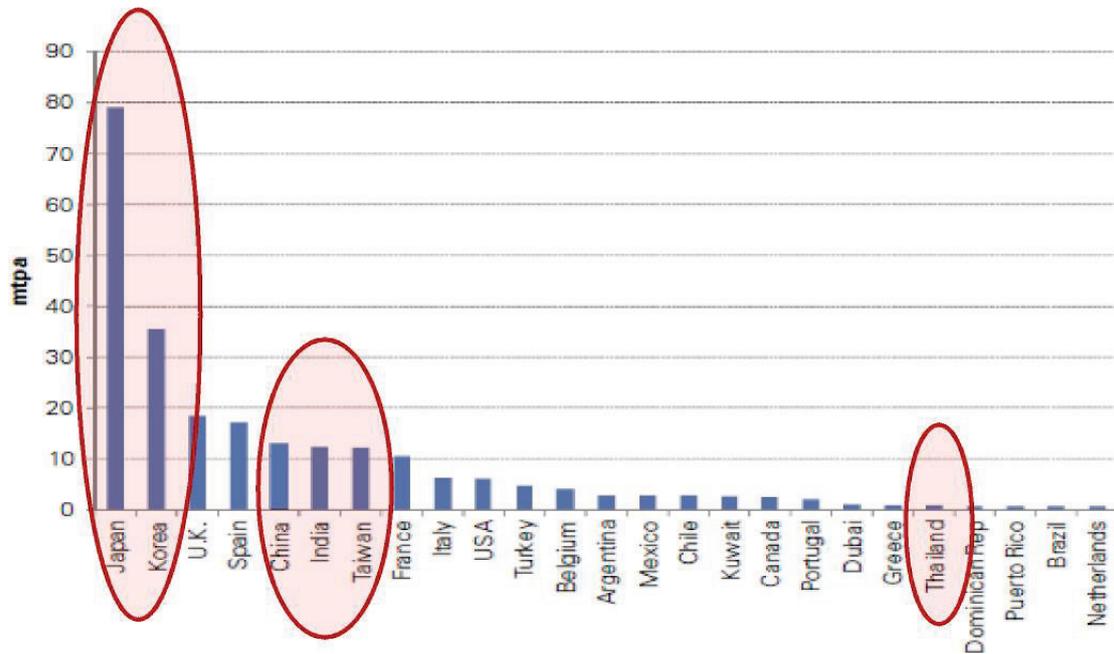


Figure 15: Huge market potential in Asia for LNG
 Source: Goldman Sachs, Asia Pacific: Energy, 21 August 2012

This section of the report will focus on three potential Asia Pacific LNG Markets for Canada. It will look at their present natural gas consumption, their gas industry and infrastructure. In the case of Japan, we will further explore the impact of Fukushima for the natural gas demand for the country and for China – impact of the shale plays on its LNG imports.

JAPAN – CONSUMPTION, GAS INDUSTRY AND INFRASTRUCTURE

Natural gas consumption patterns:

In 2010, Japan consumed about 3.7 Tcf of natural gas, importing over 3.4 Tcf of LNG by tanker. As a result of the March 2011 earthquake, Japan's LNG imports rose 12 percent in 2011 to 3.8 Tcf, according to some industry sources. IHS CERA estimated that total natural gas imports increased by a monthly average of 18 percent annually from April 2011 through February 2012 compared with the pre-earthquake increases of 4 percent year-on-year between January and March 2011. LNG consumption by the electric utilities rose by 20 percent annually to a record-high of 2.4 Tcf in 2011.

In 2011, Japan stands out as the world's no. 1 LNG importer with 79.1 Mt compared to 70.9 Mt in 2010 (+11.6%). Japan accounted for 41.6% of Asia's additional LNG's imports in 2011 and the country's share of global LNG imports increased from 31.6% in 2010 to 32.8%.⁶²

Gas Industry:

According to EIA, Japan produced 174Bcf⁶³ of natural gas in 2010. Japan's largest natural gas field is the Minami-Nagaoka on the western coast of Honshu, which produces about 40 percent of Japan's domestic gas. Exploration and development are still ongoing at the field which Inpex discovered in 1979. The gas produced is transported via an 808-mile pipeline network that stretches across the region surrounding the Tokyo metropolitan area. Inpex is building an LNG terminal with a 73⁶⁴ Bcf/y capacity at Naoetsu port in

⁶² GIIGNL (International Group of Liquefied Natural Gas Importers). 2012. The LNG Industry in 2011. See Appendix for contracts as well.

⁶³ EIA – Japan Country Profile (June 2012). <http://www.eia.gov/countries/cab.cfm?fips=JA>

⁶⁴ Ibid

Joetsu City which will connect its domestic pipeline infrastructure with its overseas assets by 2014. Japex has been involved in locating new domestic reserves in the Niigata, Akita, and Hokkaido regions of Japan, targeting structures near existing oil and gas fields.

Japanese companies are using innovative methods to produce hydrocarbons and discovered methane hydrates off the country's east coast. Japan estimates about 40 Tcf of methane hydrates may exist and hopes to begin production by 2018. The high cost of such developments could push back production plans.

According to EIA, Japanese regulations permit individual utilities and natural gas distribution companies to sign LNG supply contracts with foreign sources, in addition to directly importing spot cargoes. The largest LNG supply agreements are held by Tokyo Gas, Osaka Gas, Toho Gas, Chubu Electric and TEPCO, primarily with countries in Southeast Asia and the Middle East. Many of Japan's existing LNG contracts date from the 1970s and 1980s, and are set to expire over the next decade forcing Japan to renegotiate term contracts or locate shorter term supply. Some industry analysts suggest that this is driving Japanese firms' interest in acquiring equity stakes in foreign liquefaction projects, in an effort to guarantee future supply. We have already seen a potential LNG terminal between Nexen (CNOOC) and Inpex.⁶⁵

Infrastructure

There is no national gas pipeline network because of topography. LNG is delivered to industrial and urban demand centers. Coastal shipping of compressed gas could be used to link segments. Retail gas distribution utilities typically own the local pipeline networks. Most of the LNG terminals are owned by electrical utilities either alone or in partnership with local gas distribution utilities. Table 9 shows the location and gas send-out capacity of Japan's LNG receiving terminals. Send-out capacity is the daily volume of gas the terminal can send out to the gas distribution network. The terminals are located near major urban and manufacturing cities. The LNG terminal owners also own much of the country's LNG tanker fleet. The annual capacity of existing receiving terminals is 8.4 Tcf/Y, more than twice 2010 imports of LNG. Gas demand in Japan has a large seasonal component. In the absence of massive gas storage facilities, the extra import LNG terminal capacity is required to meet the peak seasonal demand.⁶⁶

Japan permits individual electric utilities and gas distribution companies to sign gas supply contracts with foreign sources as well as to import spot cargoes directly. In 2010, Japan imported more than 75 percent of its LNG from Pacific regional producers. Other suppliers were Qatar and the United Arab Emirates. Imports are commonly from projects where equipment manufacturers and gas and electrical utilities have equity interests.

Japan has made significant investments in upstream natural gas exploration and development, liquefaction facilities, LNGCs, and LNG regasification terminals. Australia's share of Japan's LNG imports will increase as projects that are currently under construction come on-stream before the end of 2018.⁶⁷

⁶⁵ Nexen Inc. "News Release – Nexen Announces Sale and Joint Venture Partnership for Northeast British Columbia Shale Gas Assets". November 29, 2011. http://www.nexeninc.com/en/AboutUs/MediaCentre/NewsReleases/News/Release.aspx?year=2011&release_id=117759

⁶⁶ Emil D. Attanasi and Philip A. Freeman - The Role of Stranded Gas from Central Asia, Russia, Southeast Asia, and Australia in Meeting Asia's Future Demand for Gas Imports. 2012

⁶⁷ GIIGNL (International Group of Liquefied Natural Gas Importers). 2012. The LNG Industry in 2011. See Appendix for contracts as well.

Japan

- Largest importer of LNG. Post April 2011, significant increase in LNG use.
- 32 LNG terminals, ~ 23.8 Bcf/d of send out capacity (>2 x its 2011 daily average consumption)
- ~ 15 MMCM of liquid storage capacity (~ 318 Bcf of Natural gas)
- 5 terminals under construction (Adding 0.55 to 0.82 Bcf/d capacity)
- Gas and electric companies own LNG terminals and much of the LNG tanker fleet

Source: IEA, IGU 2012

Japan – World's largest LNG importer

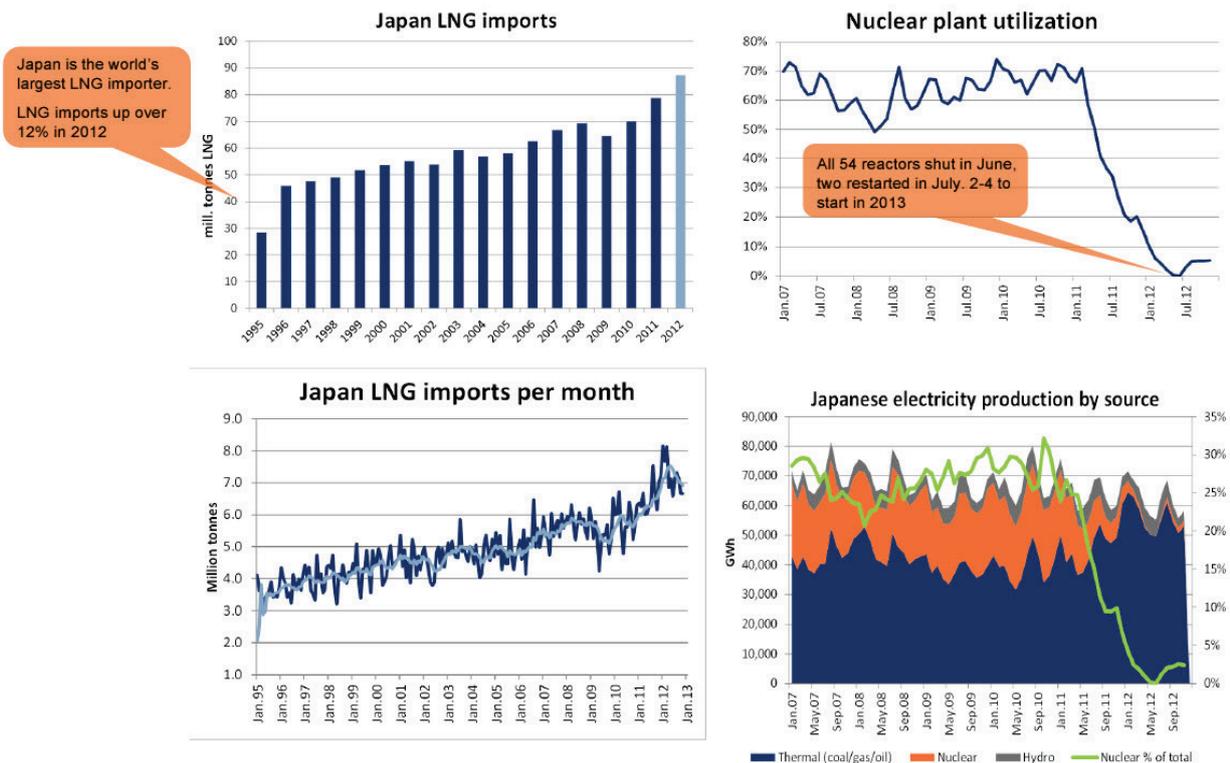


Figure 16: Japan is presently world's largest LNG Importer
Source: Hoegh LNG – The floating LNG Services provider (January 15 2013)

Role played by the earthquake on Japanese LNG demand

Following the events of the tsunami and subsequent reactor meltdowns at Fukushima in March 2011, all of Japan's 50 operational nuclear reactors were progressively shut down (although Japanese regulations require a shut down every 13 months for maintenance and inspection).

About 12 GW's of nuclear capacity in Japan had to be shut down due to the earthquake, which when translated to roughly 80 mmcm/d of gas demand. The earthquake will have a long lasting impact on the relative use of gas in Japan. Plants unaffected by the tragedy were not permitted to restart and by May 2012 the last reactor had shut down. For the first time in decades, there were no reactors operating in the whole country.⁶⁸

The role of LNG as a flexible and secure energy source was very evident during the period. LNG suppliers were prompt in their response to provide back-up through additional supplies and cargo diversions This

⁶⁸ Bill Sooby and Pat Roberts (CWC LNG and Gas Leaders forum) - Japanese Nuclear Reactors Restart – Is this a turning point for the Global LNG Industry

helped Japan to compensate for the sudden loss of nuclear capacity. The increase in LNG production capacity in 2009 and 2010, in particular from Qatar, had permitted the necessary buffer to cope much better with the demand surge than during past disruptions (such as the aftermath of the Chuetsu earthquake in late 2007). The IEEJ estimates that Japan imported 83.13 million tonnes in fiscal 2011, an 18 percent increase. This has created a premium in Japanese LNG pricing.⁶⁹

The current position is that there is substantial uncertainty over Japanese LNG demand going forward. Estimates of LNG demand in 2020 now range from about 60 mtpa to over 90 mtpa. The lower figure was based on the national strategic energy plan, which foresaw greater dependence on nuclear power. However with the earthquake and its negative impact it is very likely this value will be exceeded. The higher figure assumes some nuclear generation. In fact, a politically driven decision to end all nuclear output could push demand even higher and result in fast tracking new gas power plants and extending Japan's gas infrastructure. The wide differences in Japan's likely firm future LNG demand are equal to about 10% of today's global production.⁷⁰

SOUTH KOREA: CONSUMPTION, GAS INDUSTRY AND INFRASTRUCTURE

EIA estimates that South Korea was the world's tenth largest energy consumer in 2011, and with its lack of domestic reserves, Korea is one of the top energy importers in the world. In 2011, the country was the second largest importer of liquefied natural gas (LNG), the third largest importer of coal, and the fifth largest importer of crude oil. South Korea has no international oil or natural gas pipelines, and relies exclusively on tanker shipments of LNG and crude oil. It is one of the major importers of LNG and Canada is an emerging exporter of the resource.

Natural gas consumption patterns:

With LNG imports growing by 8.9% and total imports representing 35.6 Mt, Korea ranked second globally. Its share of the global LNG market remained nevertheless unchanged at 14.8%.⁷¹

According to EIA, South Korea consumed 1.6 trillion⁷² cubic feet (Tcf) of natural gas in 2011, which was an increase of more than 125 percent from 2001. The city gas network, serving residential, commercial and industrial consumers, accounted for the majority (54 percent in 2011) of natural gas sales, while power generation companies made up nearly all of the remaining share. South Korea imports 42 percent of its LNG demand from the Middle East, 35 percent from Southeast Asia, 8 percent from Russia, 6 percent from Central and South America and 6 percent from Africa. South Korean economic fundamentals remain strong including its sovereign creditworthiness and healthy government finances. Its credit worthiness has increased most among the OECD countries in the last five years. South Korea has experienced a total of four advancements since end 2007 (two notches by Moodys to Aa3, one by S&P to A+ and one by Fitch to AA-. This solid economic growth reflects continued LNG demand opportunities for South Korea. LNG demand exceeded Korea Ministry of Knowledge Economy 10th long term plan as shown below-

⁶⁹ Morikawa, T. & Hashimoto, H. 2012. Japan's new challenge and possible solutions in LNG procurement activities in the wake of less availability of nuclear power capacity. IEEJ.

⁷⁰ Bill Sooby and Pat Roberts (CWC LNG and Gas Leaders forum) - Japanese Nuclear Reactors Restart – Is this a turning point for the Global LNG Industry

⁷¹ GIIGNL (International Group of Liquefied Natural Gas Importers). 2012. The LNG Industry in 2011. See Appendix for contracts as well.

⁷² EIA – South Korea (Jan 2013). <http://www.eia.gov/countries/cab.cfm?fips=KS&scr=email>

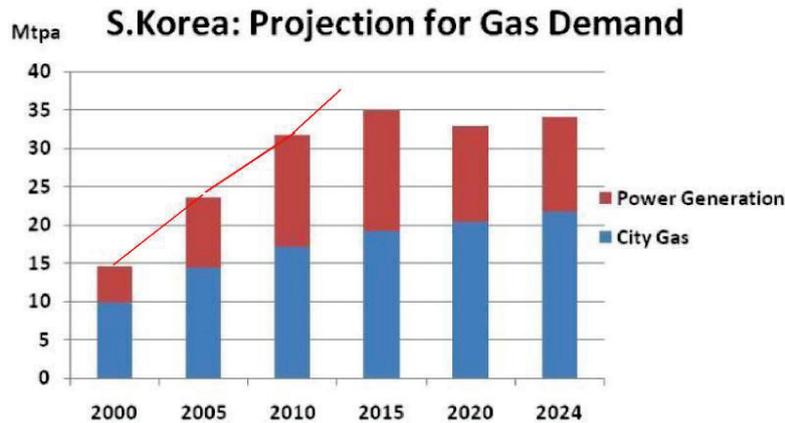


Figure 17: South Korean Natural Gas Demand

Source: JX Nippon Research Institute, Ltd; Korean Ministry of Knowledge Economy 10th Long term Gas Plan

Gas Industry:

South Korea produced about 18 Bcf of natural gas (about 1.3 percent of consumption) in 2011 from the domestic gas field in production, Donghae-1 in the Ulleung Basin. KNOC will continue production operations until 2018, when the project will be converted into an offshore storage facility. State-owned Gas Hydrate Research & Development has conducted studies of deposits of methane hydrates in the Sea of Japan, and the government has previously announced plans to start extracting methane hydrates from the sea by 2015.

As part of the effort to develop into a global integrated energy company, KOGAS is participating in 26 projects, 13 of which are either solely E&P projects in 16 countries. South Korea holds equity shares in four production-stage projects, namely 50 percent in Canada's Encana project, 3 percent in Qatar's RasGas project, 8.9 percent in Yemen's YLNG project, and 1.2 percent in Oman's Oman LNG project. It is KOGAS' mid-term goal to secure 25 percent of gas imports from equity production sources by 2017.⁷³

Infrastructure:

South Korea has four LNG regasification facilities, with a total capacity of 4.5 Tcf per year. KOGAS operates three of these facilities (Pyongtaek, Incheon, and Tong-Yeong), accounting for about 95 percent of current capacity. Pohang Iron and Steel Corporation (POSCO) and Mitsubishi Japan jointly own the only private regasification facility in Korea, located on the Southern Coast in Gwangyang. In 2011, South Korea imported 1.6 Tcf of LNG. KOGAS purchases most of its LNG through long-term supply contracts, and uses spot cargos primarily to correct small market imbalances. Almost two-thirds of 2011 natural gas imports came from Qatar, Indonesia, Malaysia, and Oman.

Nearly an additional 1 Tcf of regasification capacity had been added since 2010. In addition to recent expansion of existing facilities, KOGAS is planning a new 487 Bcf per year facility at Boryeong, whose first unit is scheduled for completion by 2013, second by 2019. KOGAS is currently constructing a new LNG receiving facility at Samcheok, on the Northwest coast. The first stage of 278 Bcf per year is slated for 2013 completion, with supplies of 350 Bcf per year to be met primarily through gas imported from Vladivostok, Russia starting in 2015. Although the associated 2008 KOGAS-Gazprom Memorandum of Understanding indicated that the gas could be imported either as LNG or pipeline gas from Vladivostok, Russian and Korean leaders recently acknowledged that the pipeline construction option most likely will not be deemed economically feasible without the cooperation of North Korea.⁷⁴

⁷³ EIA – South Korea (Jan 2013). <http://www.eia.gov/countries/cab.cfm?fips=KS&scr=email>

⁷⁴ EIA – South Korea (Jan 2013). <http://www.eia.gov/countries/cab.cfm?fips=KS&scr=email>

South Korea

- Second largest importer of LNG
- Strong, stable economy
- 4 LNG terminals, ~ 11.4 Bcfpd of send out capacity
- Construction of two storage sites at Samcheok and Bronghae underway
- Equity Investment: Import terminals owned by Korean gas corp. (KOGAS) (main LNG infrastructure owner in Korea), SK E&S, GS Caltex and POSCO

Source: IEA 2011

CHINA: CONSUMPTION, GAS INDUSTRY AND INFRASTRUCTURE

Note: The primary assumption made in this section of my report is that the Chinese government is serious about environmental issues so there will be a growing emphasis to natural gas over coal. There is an expectation that since China is becoming a net importer of coal, it is now exposed to international pricing and this will cause an upward pricing of coal. In Copenhagen, it had agreed to cut per capita emissions by at least 40% by 2020. This will help natural gas overcome some of its economic disadvantages in China.

Natural gas consumption patterns and pricing reforms:

China is the world's most populous country and the largest energy consumer in the world. Rapidly increasing energy demand has made China extremely influential in world energy markets. According to the EIA, although natural gas use is rapidly increasing in China, the fuel comprised less than 4 percent⁷⁵ of the country's total primary energy consumption in 2009. It will see the largest growth in natural gas demand from 2010 to 2040, accounting for nearly half of Asia Pacific Non OECD demand growth. Low gas penetration thus far suggests China could radically increase its demand for gas – the question is whether it can drive gasification using domestic unconventional gas resources, or feels compelled to draw in further higher-cost import gas sources. In the short to medium term, China has secured enough gas to meet growth and is using the next plan period (2011-15) to assess how significant domestic shale/tight and CBM production could be in the latter part of the decade (and if it will need to commit to further pipeline gas/LNG to meet gas demands at that time). While China waits, lower-cost gas suppliers have time to firm up their LNG offer (e.g. in East Africa).

China

- 5 LNG terminals, ~ 2.7 Bcfpd of send out capacity, another ~ 2 Bcfpd expected to be built by 2015
- More than 20 import terminals under construction or in approval process
- More than 90% of terminals will be owned by Chinese NOC's
- CNPC owns 2 recently completed

Source: EIA 2012

Traditional Gas Pricing and Reforms: Chinese gas has been traditionally priced on a Cost Plus Basis⁷⁶, it is a subsidy pricing system, the system was possible when China was self-sufficient in gas and gas was supplied by government companies, it is less effective in a world of growing dependence on imports at higher international price levels. The government of China regulates wellhead and wholesale natural gas prices of domestically produced gas to assure their industries remain competitive. At the retail level China has gradually implemented price increases for oil and gas so that domestic prices more closely track

⁷⁵ In 2010 gas accounted for just over 4 percent of China's primary energy consumption, coal 70 percent, oil 18 percent, hydro 7 percent, and nuclear less than 1 percent of primary energy consumption.

⁷⁶ Prices are regulated and generally well below international market. Wholesale and retail prices are linked to production and delivery costs.

international prices. Gas prices vary regionally based on pipeline infrastructure and the regional mix of gas consumers.⁷⁷ Recently, China recently announced a new natural gas pilot reform to take effect in two southern provinces, Guangdong and Guangxi. The reform aims to gradually liberalize gas prices by linking them to imported oil products—a key step toward more market-based pricing. The new system links gas prices to market-set import prices for liquefied petroleum gases and residual fuel oil.

Gas Industry and Infrastructure: Impact of the Chinese shale's on China's LNG Imports

According to OGJ, China had 107 trillion cubic feet (Tcf) of proven natural gas reserves as of January 2011. China natural gas production in 2011 reached 101 trillion cm. In 2009, China produced 2.93 Tcf of natural gas. The newly booked natural gas reserves for 2011 reached 76,6 trillion cm. Sichuan added 278.4 trillion cm, Ordos added 229.7 trillion cm, Tarim added 108.4 trillion cm, Songliao added 29.8 trillion cm. CBM added reserves 415.6 trillion cm.⁷⁸

China's primary natural gas-producing regions are Sichuan Province in the southwest (Sichuan Basin); the Xinjiang and Qinghai Provinces in the northwest (Tarim, Junggar, and Qaidam Basins); and Shanxi Province in the north (Ordos Basin). China has dived into several offshore⁷⁹ natural gas fields located in the Bohai Basin (Yellow Sea) and the Panyu complex of the Pearl River Mouth Basin (South China Sea) and is exploring more technically challenging areas, such as deep-water and unconventional resources, with foreign companies.⁸⁰ With the completion of the West to East Pipeline linking the Tarim basin to Shanghai, activities in the basin have kicked up a notch, however this gas is a long way from the market and will be costly to deliver.

Shale Gas developments in China. The unconventional gas industry in China is in nascent stages of development due to technical challenges, regulatory hurdles, transportation constraints, and competition with other fuels and conventional natural gas. However, China's potential wealth of unconventional gas resources such as coal bed methane (CBM) and shale gas has spurred the government to seek foreign investors with technical expertise to exploit these reserves.⁸¹ Most of China's shale gas resources reside in the Sichuan and Tarim basins in the southern and western regions and in the northeast basins. In early 2010, the Ministry of Land Resources set out its goals regarding shale gas: to produce 530 to 1,000 Bcf/y, accounting for 8 to 12 percent of China's total natural gas from shale gas by 2020. EIA estimates that China's technically recoverable shale gas resources are 1,275 Tcf.

China's National Petroleum Assessment 2010 (CNPA) results show that China's undiscovered oil and gas recoverable resources are respectively 108.7 billion bbl of oil and 990.7 trillion cu ft of gas. Gas resources are mainly distributed in the three large-scale basins, including the Ordos, Tarim, and Sichuan basins.⁸²

China's goal is to attain shale gas recoverable reserves of 600 billion cu m and output of 6.5 billion cu m/year. Chinese total shale gas production rate is to reach 15-30 billion cu m/year by the end of 2020, amounting to 8-12% of Chinese total natural gas production by that time.⁸³

⁷⁷ The Role of Stranded Gas from Central Asia, Russia, Southeast Asia, and Australia in Meeting Asia's Future Demand for Gas Imports

⁷⁸ <http://www.eia.gov/countries/cab.cfm?fips=CH>

⁷⁹ There are also reserves offshore, but boundary disputes complicate some of the prospective areas.

⁸⁰ <http://www.eia.gov/countries/cab.cfm?fips=CH>

⁸¹ *ibid*

⁸² <http://www.ogj.com/articles/print/vol-110/issue-06/exploration-development/china-updates-data-on.html>

⁸³ <http://www.ogj.com/articles/print/vol-110/issue-3/exploration-development/china-vigorously-promoting.html>

Challenges for Shale gas developments:

- Pipeline investments: As shale gas production ramps up, China will need to build pipeline and therefore the investment costs for these pipelines will be very high. Most of the existing pipelines in China is managed by Petro China. Upstream shale gas players will find getting access to these pipelines challenging and access will be difficult.
 - Terrestrial shales underlie 20,000-25,000 sq km, mainly in the Junggar, Tuha, Bohai Bay, Ordos, and Qaidam basins.
 - Sea-land transition shales underlie 15,000-20,000 sq km in northern China.
 - Marine shales underlie 60,000-90,000 sq km in southern China, north China, and the Tarim basin.
- Lack of clear regulatory processes in place to define and contrast between shale gas resources and conventional natural gas resources.
- Natural gas price reforms: Since the conventional gas prices are strictly regulated, the well head price will have to follow market pricing that would be one way to incentivize the shale gas players.

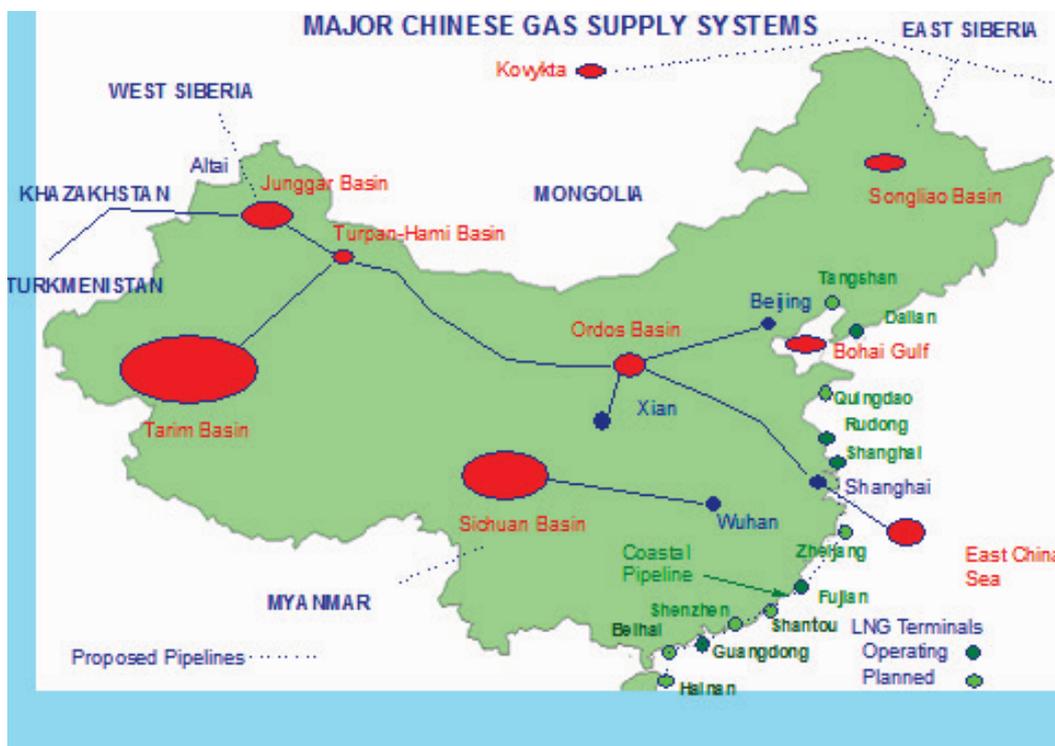


Figure 18: Major gas fields in China

Source: James Jensen – Emerging LNG Market Demand (June 2011)

Conclusion:

China’s unconventional gas although being huge will take a longer time to develop due to environmental challenges, so there will be plenty of opportunity for LNG exports to the country.

EMERGING LNG BUYERS

The other potential LNG importers for Canada are Thailand, Singapore, Indonesia, Malaysia and Vietnam. All of them are based out of Southeast Asia. Singapore could potentially be a price marker in Asia after the Japanese based price which is indexed to the Japan Crude cocktail and Shanghai also aims to becoming a hub.

- Indonesia, Malaysia, Philippines, Thailand, Vietnam
 - Emerging and (generally) fast growing economies
 - Large populations; growing disposable income
 - LNG imports to supplement own domestic gas production
- Singapore
 - Strong economic growth
 - Diversify supply
 - Trading hub?

Thailand, Singapore, Indonesia, Malaysia and Vietnam will import an aggregated LNG capacity of approx. 20 Million tonnes before 2015.

LNG PRICING

Mechanisms of LNG Pricing in Asia:

LNG is mainly bought and sold through long term bilateral contracts of 10 + years rather than on the basis of a traded market price. In negotiations for these long term contracts, the transaction price is determined by the buyer and seller agreeing to a price formula indexed to crude oil prices. The price formula is negotiated in the context of market circumstances such as the balance of supply and demand and crude oil prices, so a variety of formulas are used.⁸⁴ The graph below clearly indicates why all Global LNG suppliers are interested in the premium North Asian LNG markets. As far as Canada is concerned one can clearly contrast the difference between the Henry Hub price and the Japanese price and the huge advantage for the Canadian LNG project proponents if they are able to get Asian prices for their LNG.

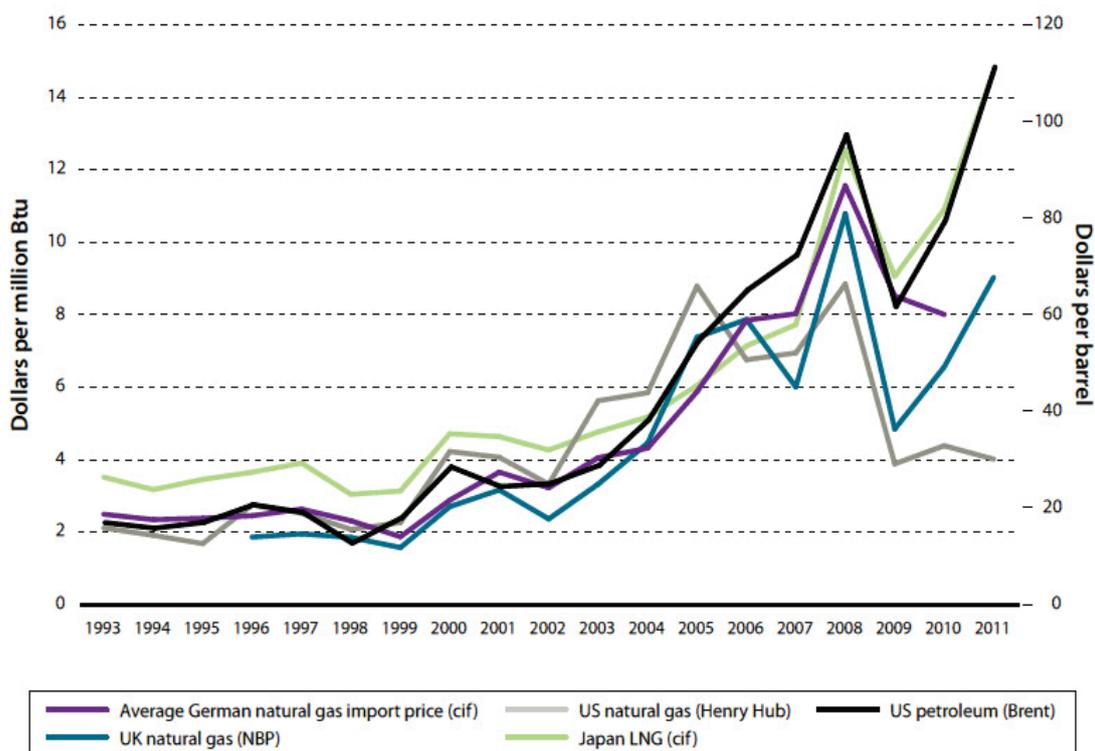


Figure 19: Select Prices of Natural gas, LNG and Brent Crude Oil (1993-2011)

Source: BP 2011, ENI (2012), Michael Levi (2012)

⁸⁴ Akbar Nazemi - NEW MECHANISMS OF LNG PRICING IN ASIA (2009)

Long term contracts will dominate in the Asian markets

According to the IEA, most of the gas delivered to Japan, Korea, China and India as LNG, as well as China's imports of gas by pipeline from Turkmenistan, is covered by long-term contracts, with indexation based on crude oil prices and destination clauses (limiting the ability of buyers to divert cargoes to other markets). Spot and short-term supplies have been growing (in part because of the unanticipated surge in Japanese demand following Fukushima), but buyers in the region have traditionally placed strong emphasis on long-term security of supply. In some cases, large buyers— including Japanese, Korean and Chinese companies—have taken stakes in the upstream projects especially in Canada, US and Australia in order to share in the rent that might come about as a result of higher oil prices (as well as, in some cases, to learn about the technologies involved).

Why costs matter?

Given the capital-intensive nature of liquefaction projects, long-term contracts requiring the purchase of high volumes are often used to ensure high utilization rates and to meet investment hurdle rates. Given sensitivities around pricing for newer LNG buyers, LNG pricing will be a key consideration in whether a project will succeed or not. The issue is that high construction costs on new Greenfield projects are making it difficult for sellers to offer competitive pricing terms. Liquefaction costs have increased in recent years to \$ CDN. \$1,000/ton⁸⁵ of annual capacity.

The best positioned LNG projects are those with the lowest all-in capital costs, which could be due to a number of factors, including:

1. Presence of existing infrastructure, making brownfield expansions more economic,
2. Low upstream production costs thanks to geological factors:
 - a. Horn River. The Horn River is a thick, highly productive shale, but its distance from market and high CO₂ content push breakeven prices to \$4.75/mmbtu (at Henry Hub). Once gas prices exceed that breakeven price, development should accelerate, and highly productive wells will build supply quickly. If more than 1 bcfpd of export capacity is completed,
 - b. Montney. The Montney play could earn returns primarily with liquids; gas breakevens, including a 10% IRR, in all three plays are below \$3.25/mmbtu. In the Montney, higher gas prices support returns in these plays even with liquids under pressure.⁸⁶
3. Associated liquids content,
4. Favourable fiscal terms,
5. Proximity to consuming markets resulting in low transportation costs, particularly to Asia. Extensive transportation networks required for gas to be consumed on-site by final consumers. Natural gas is roughly 10x as expensive to transport as crude oil, so transportation cost represents much higher portion of final price of gas to consumer. Prices are set in consuming market, so producers must pay transport cost. This means potentially there could be significant differences between final consumer prices and field prices for gas, depending on distance to markets means natural gas markets are regional, not global, and prices may vary significantly between regions (as opposed to global markets and highly uniform prices for crude oil)
6. Beyond purely economic factors, some buyers (particularly traditional buyers in East Asia) continue to value security of supply and will therefore retain a preference for exporting countries seen as “lower risk” e.g. Japan did not participate in Yemen LNG. Companies with only one or two LNG projects in their portfolio may find it more difficult to persuade buyers to sign long-term contracts than larger companies with diversified supply portfolios.

⁸⁵ Credit Suisse – Global Gas (Nov 2011). P. 19.

⁸⁶

LNG versus Pipelines costs

Furthermore, over long distances, transporting natural gas in liquid form (i.e., LNG) is more cost effective than using inter-regional gas pipelines over the same distance. Figure below shows the effects of transporting by pipeline and by LNG

**ILLUSTRATIVE COSTS [1] OF GAS AND OIL TRANSPORTATION
SHOWING GAS'S HIGHER COSTS
AND THE EFFECT OF SCALE
(Gas Delivery Capability in BCM)**

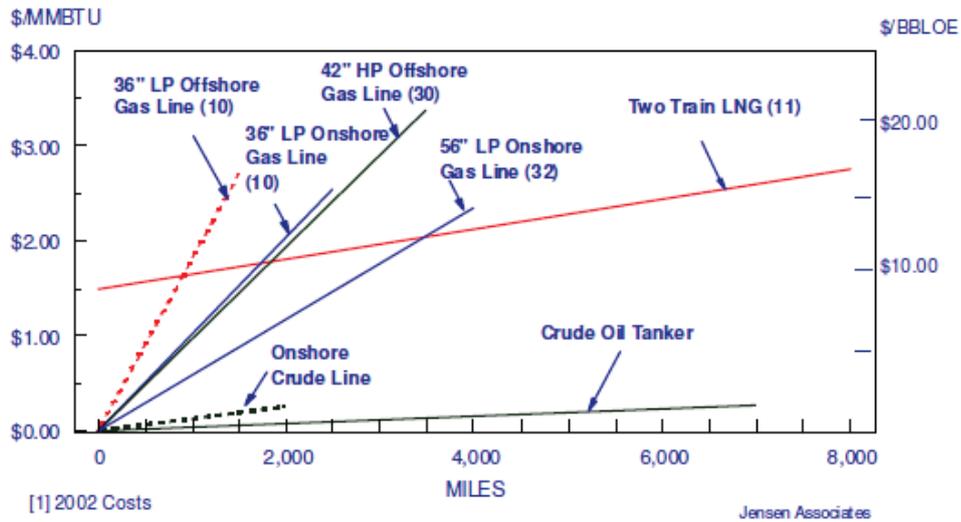


Figure 20: Illustrative costs of gas and oil transportation

Source: Jensen, J. Asian Natural Gas Markets Supply Infrastructure and Pricing Issues. Pacific Energy Summit held February 21-23, 2011 in Jakarta, Indonesia.

Historical LNG Pricing Formulae

LNG pricing in Asian markets, which comprised around 65% of world consumption in 2007, has historically taken the form of an “S-curve” based on a formula of the form:

$$P(\text{LNG}) = ax + b \dots\dots\dots(1)$$

x is the price of a basket of crudes imported into Japan, the Japanese Crude Cocktail (JCC).).⁸⁷

More conveniently, US\$JAPANESE CRUDE COCKTAIL (JCC). ~ US\$WTI – US\$1.00.....per barrel

The “a” factor offers a premium price to the Canadian gas suppliers, and the “b” factor covers the full cost of liquefaction, transportation and regasification. The values of a and b are negotiated individually in each contract. There are often floors and caps on the LNG price set by (1). These floors and caps also vary with the price of oil, but with a lower slope than (1), resulting in an “S” curve. A “floor” price may effectively protect the producer’s investment whereas a price “cap” provides a quid pro quo for the LNG buyer. There are also specific “meet & discuss” clauses in any contract to take account of unusual or unanticipated conditions or situations.

The slope, a, of the curve, a reflection of the correlation of LNG prices to oil prices, and the inflexion points at which the correlation is weaker than a. A pricing formula is illustrated in Figure 21 below:

⁸⁷ Although not as easy to follow as other benchmark crudes such as WTI or Brent, it is a public domain price

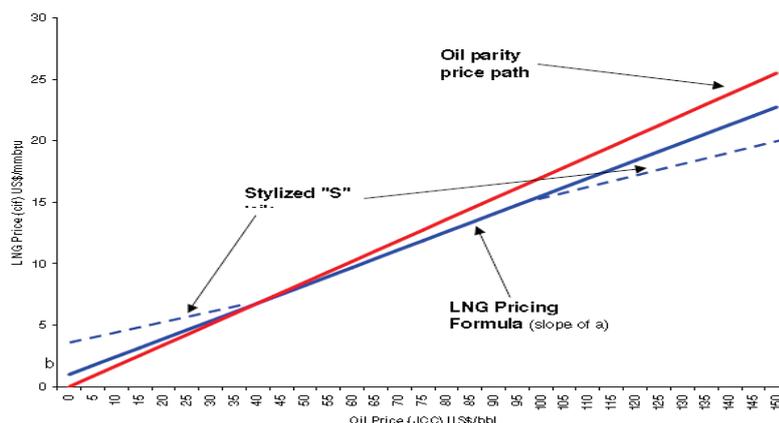


Figure 1: Conceptual "S" formula

The pricing formula recommended in the May 2006 report, often referred to as the "Guangdong formula", was of the form:

Figure 21

Source: Gary Eng - A Formula for LNG Pricing – An Update

Some additional LNG Pricing Formulas to India

- GAIL Formula = $1.17 \times \text{Henry Hub Price} + \5.90 . This is a new form of contract currently under development, based on LNG exports from the USA to India, and is obtained from media reports⁸⁸. The "a" factor offers a premium price to the US gas suppliers, and the "b" factor covers the full cost of liquefaction, transportation and regasification. Historically, the lower 48 US states have been gas importers, including LNG, not exporters, but this is now changing with the shale gas glut on the market and low gas prices.
- Other LNG pricing formulas to India is depicted in Table 12.⁸⁹

Table 12

LNG Source	Year of Contract	Delivery Type	Year of Commencement of LNG Supplies	Annual LNG Quantity	Supply duration	Pricing Formula
Qatar	1999	FOB	2004	7.5 MTPA	25 years	12.67% ^{90*} Japanese Crude Cocktail (JCC).
Australia ⁹¹	2009	FOB	2014	1.4 MTPA	20 years	14.50%* Japanese Crude Cocktail (JCC).
Russia ⁹²	2012	Not Available	Not available	2.5 MTPA	20 years	Linked to NBP Price

⁸⁸ See <http://www.reuters.com/article/2012/01/16/india-lng-gail-idUSL3E8CG2X420120116>.

⁸⁹ Based on private communication with consultants from India.

⁹⁰ If JCC = \$ 100 per barrel, then contract price will be 12.67% of 100 = \$ 12.67 per mmbtu

⁹¹ Australia- India LNG Trade

[http://minister.ret.gov.au/MediaCentre/MediaReleases/Pages/AustraliaSigns\\$25BillionGorgonLNGDealwithIndia.aspx](http://minister.ret.gov.au/MediaCentre/MediaReleases/Pages/AustraliaSigns$25BillionGorgonLNGDealwithIndia.aspx)

⁹² Russia- India LNG trade <http://www.naturalgaseurope.com/russia-lng-sector>

The historical relationships between the US, European and Asian gas markets have tracked each other for over twenty years, however in 2009, the relationship seems to have broken down. It is this break in price relationship that the North American - especially the Greenfield Canadian LNG crusaders are targeting. They are targeting the premium priced Asian gas prices to ship their cheaper Canadian gas. My assumption is that the natural gas pricing will not converge any time soon since the heavy producers Qatar and Russia are restraining their production quota and majority of the long term contracts from Canada would be priced on an oil linked basis.⁹³

IS LNG A LONG-TERM BUSINESS OPPORTUNITY FOR CANADA – A SWOT ANALYSIS

Before concluding what could be the market potential for Canadian LNG, the various stakeholders of the Western Canadian LNG projects need to understand the environment they would be operating in, and identify the challenges they may face. An environmental scan helps us understand that environment and how the LNG from the Canadian West Coast relates to its external environment. The scan usually includes an internal component -- assessing sectoral strengths and weaknesses -- and an external component -- identifying and assessing opportunities and threats in the external environment. This process is often referred to as “SWOT” analysis: identifying and assessing Strengths, Weaknesses, Opportunities, and Threats.

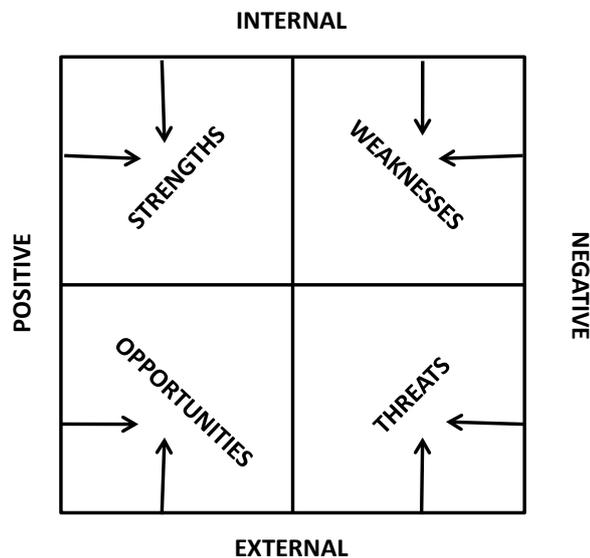


Figure 22: SWOT Schematic

The internal component of the e- scan involves an assessment of the Canadian LNG’s strengths and weaknesses. A key aspect of this will be around the magnitude and nature of Western Canada’s natural gas resources, their ability to serve the present and future energy needs of Asian markets and their ability to generate revenues for the Government of Canada to strengthen the Canadian economy and enhance the welfare of Canadians beyond just their energy needs.

The external component includes a review of the broader environment in which the Canadian LNG sector would operate, to identify opportunities and threats facing the sector. Note that external here does not necessarily imply external to Canada, but rather external to the Canadian Natural gas sector, including changing demographics, political trends, community values, economic trends, new or changing laws and regulations, communications and other technological trends -- and the LNG proponents could consider the impact of these factors on Canadian LNG projects, the population and markets it serves, and whether these factors represent opportunities or threats.

⁹³ Michael Levi- A Strategy for US Natural gas exports (June 2012). P. 10.

Strengths

- Supply Potential for Western Canadian Natural Gas: Recent discoveries in the Horn River basin and the Montney plays are expected to approximately triple British Columbia natural-gas production from -2.8 B/D currently to 7.6 B/D⁹⁴ within approximately the next 10 years. The natural gas resource base in British Columbia is expected to be on the scale of other major liquefied natural gas (LNG) producing nations (e.g., Indonesia and Australia). All of the major Canadian exploration companies, together with several of the super majors and some independents, are developing natural gas in the Montney and Horn River shale plays
- Canadian exports have some positive features over those from the US (both Gulf of Mexico and West Coast). Historically, gas in Western Canada has traded at a discount to Henry Hub (HH) making it relatively very cheap today.
- There is strong political support for gas exports, unlike in parts of the US where there are concerns over future energy self-sufficiency.
- There is support from the First Nations in the area where the LNG plants would be sited.

Weakness

- LNG from Canada are mostly Greenfield projects. There needs to be infrastructure build up especially a new pipeline is needed to get the gas from the West Coast Mainline (the principal North/South pipeline in the area) to the coast itself and there is no existing LNG infrastructure in the area. This will increase the costs substantially.
- Time and cost of regulatory process and procedures⁹⁵: Considerable time is frequently required from when an application is filed with the National Energy Board (NEB) for permission to construct a pipeline or a related facility for oil or natural gas exports until a decision is made on the application. Given the economic opportunities from LNG exports to markets in Asia-Pacific countries that is outlined, regulatory proceedings that are drawn out to this extent will be extremely costly in terms of unrealized employment, labor income, and economic growth.

Opportunities

- LNG projects from Canada has compelling economics because it provides an option to access strategic markets in the Pacific basin and to take advantage of the established differential in natural-gas pricing between Canada / North America and Asia. The structural price-spread difference between Asia and North America is long term in nature. Long-term LNG contracts allow western Canadian producers to link gas prices to an index linked to crude prices. Pricing differentials of \$ USD 8-10 between LNG pricing and the Canadian market price were typical in 2008. Costs to transport Canadian natural gas to BC ports like Kitimat/ Prince Rupert etc. and to liquefy it are estimated to be in the \$ CDN 3 to 4 ranges. Therefore, an overall favorable price differential exists.
- North American gas prices are forecast to remain in the \$ USD 4-6/ Mcf range at the Henry Hub and further discounted at AECO (ALBERTA ENERGY COMPANY), standard gas trading price in Alberta, which will be the benchmark used for BC's natural gas. Here is the opportunity for Canadian LNG producers to access the premium priced Asian LNG markets.
- BC to get premium value for their gas if it were to be shipped to the Asian markets, where the landed prices for natural gas are highest in the world. The crude-oil price index used in Asia is the Japan customs-cleared price or Japanese crude cocktail (JCC). The Japanese crude cocktail (JCC). has closely tracked to West Texas Intermediate oil pricing. Oil-indexed pricing will continue for the longer term because it provides price transparency to the major Asian buyers.
- Next to crude oil, natural gas has the highest energy return on energy invested; this makes it an ideal choice to replace crude oil for transportation applications.

⁹⁴ T Wall, M Graham, PJ Young, Peter T, RS Taylor and S Harbinson, Natural Gas: The Green Fuel of the Future

⁹⁵ Fraser Institute – Laying the groundwork for BC LNG exports to Asia. P. 31.

- Economic supplies of crude oil will not be able to meet future global demand. Natural gas and coal are the only two alternatives that have enough potential to fill this increased demand, however natural gas provides a clear advantage over coal with respect to both energy efficiency and environmental impact.⁹⁶ The natural gas advantage should be advocated to the public.

Threats

- LNG projects are capital intensive. It could cost anywhere between \$ CAD 10-20 billion. The cost for an entire value chain would be anywhere from : Upstream gas extraction (Approx. 30%), Liquefaction and storage (50%), Shipping (Approx. 12%) and Regasification (Approx. 8%) for a 1.05 Bcf per day project.⁹⁷ Liquefaction EPC Costs have increased dramatically since 2006. Greenfield projects will bear a bigger risk. The potential for many projects to be delayed and developers facing stiff competition is high, if the costs are not managed.
- There are different commercial and development risks with the individual proposed LNG projects in Canada with respect to their probability of success, their timing and the evolution of the different price formulae they are looking to use.
- Globally the LNG EPC demand is rising exponentially; the planned developments are way beyond the current capabilities of the contractor talent pool. This could impact the timing of Canadian projects impacting the project economics of the projects.
- The projects are in direct competition with new LNG from Australia and importantly, the Canadian projects are in strong competition with the US Gulf, where third-party buyers can buy directly on a HH formula.

So finally to **conclude**:

CONCLUSIONS

Market fundamentals in the LNG domain are changing ways oil and gas companies will extract value from their business in the coming years. Asia is and will continue to be the most premium market and the Asian demand for LNG will continue to be substantial and we will continue witnessing an oil- linkage to the LNG pricing. Canada could become a major exporter of LNG due to the following reasons

- There is a huge increase in the global energy consumption especially in emerging economies like China and India and there is a big pull in these countries to consider energy efficiency. Demand wise, natural gas would tend to gain most.
- The Canadian natural-gas industry is in a good position to increase its natural-gas production and exports through new shale-gas resource development and use of horizontal-well, multi-frac stimulation technology. Canadian LNG projects are therefore, competitive because of the low cost unconventional gas reserves and the low cost of gas.
- Canada has a relatively stable, political and fiscal environment.
- Its proximity to the Asian markets.
- The willingness of developers to offer upstream equity to term buyers.
- Canada's reputation as a trusted country and supplier to Asian markets.
- Continued oil indexation of LNG prices.
- Henry Hub prices are forecasted to stay low then the LNG production costs would be very competitive, since the proposed projects are all Greenfield projects. If Henry Hub rises, then there is

⁹⁶ The US Environmental Protection Agency (EPA) Office of Air Quality Planning and Standards published a nationwide study of utility emissions in which emissions of 13 hazardous air pollutants were quantified in 1990, 1994, and 2010 for coal, oil, and natural gas. Coal is clearly the worst and natural gas the best in terms of reduced emissions. The comparisons are actually quite staggering, making it clear that conversion of coal-fired plants to natural gas is the most effective method to meet more-stringent environmental regulations.

⁹⁷ IHS CERA – LNG Supply Projects – American Style (June 2011)

the prospect of a scramble for demand and/or projects falling away. Either way, there ought to be a strong first-mover advantage for the project sponsors.⁹⁸

The impacts of constructing the LNG terminals and related infrastructure would directly benefit **British Columbia**. The natural gas would mostly be sourced from the Horn River, though some of the companies have assets in the Alberta side of Montney, hence there would be some sourcing of gas from Alberta as well as the projects ramp up their exports. Nevertheless, there is a great benefit to export LNG for Canada⁹⁹ as a whole.

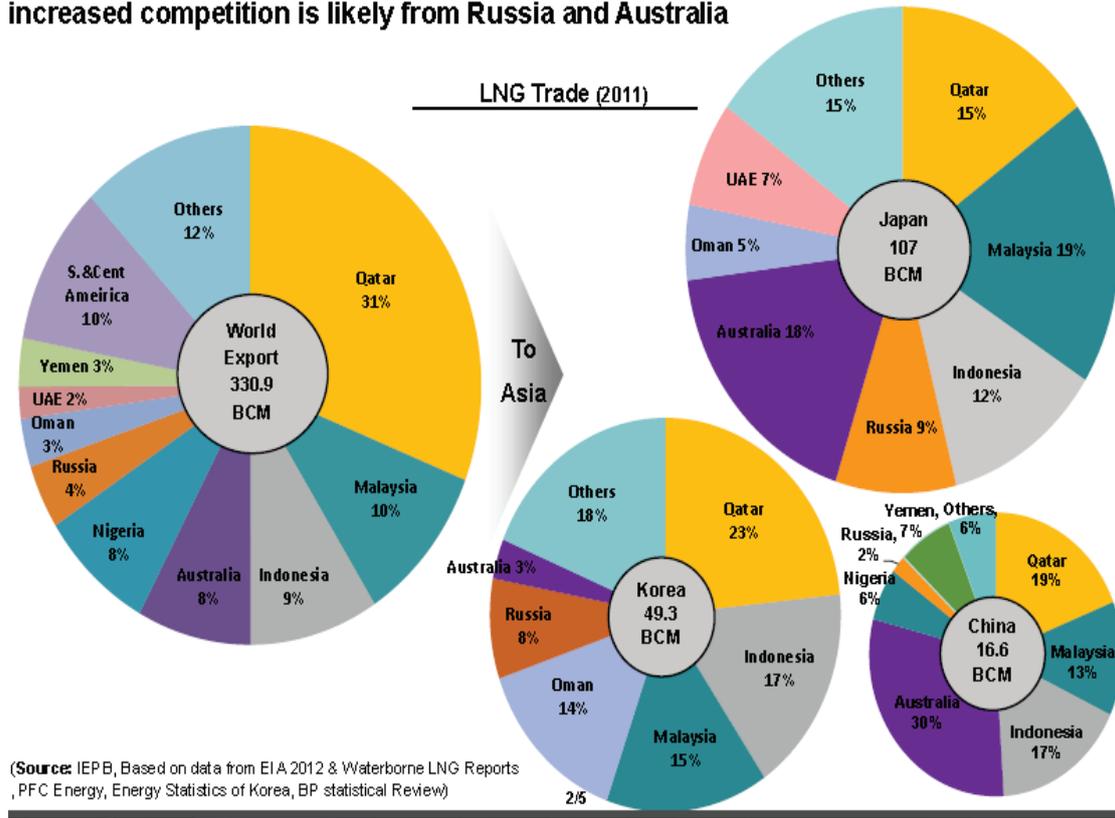
⁹⁸ Bill Sooby and Pat Roberta - LNG Exports from Canada's West Coast

⁹⁹ Huge indirect benefits would be for the manufacturing sector

APPENDIX

ⁱ The pie chart below indicates that Qatar, Malaysia and Indonesia are the largest suppliers to Asia while increased competition is likely from Russia and Australia. According to BP, the top five LNG producers, Qatar, Malaysia, Indonesia, Australia, and Nigeria, held 18.8 percent of the world’s proved natural gas reserves in 2011. Together, the five nations accounted for 65.6 percent of global LNG trade in 2011. Qatar, with the world’s third largest proved reserves of natural gas after Russia and Iran, was responsible for 31 percent of global LNG trade in 2011 compared to 25.3 percent in 2010. In 2011, Qatar accounted for 87.7 percent of the total annual increase in LNG trade

Qatar, Malaysia and Indonesia are the three largest LNG suppliers to Asia while increased competition is likely from Russia and Australia



ⁱⁱ Natural gas production (2010-2030) stats: Clearly shows the high growth in North American gas production.

