CANADIAN ASSOCIATION OF PETROLEUM PRODUCERS

Canada's Oil and Natural Gas Producers

TECHNICAL

An Overview of the World LNG Market and Canada's Potential for Exports of LNG- An Update

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1 Introduction and Executive Summary

This report provides an overview of global liquefied natural gas (LNG) trade as it currently exists and examines the potential for future growth in this market. In addition, the report examines the prospects for Canada's entry into this market and the factors behind this potential entry.

World trade in LNG has more than tripled over the last 20 years, growing from 8.5 Bcf/d (billions of cubic feet per day) in 1994 to nearly 32 Bcf/d in 2013. Although growth has stalled in recent years, it is anticipated this market will resume its rapid expansion as improved natural gas production technology means more gas reserves worldwide are available for development and demand for energy, particularly from less-emitting sources, is expected to grow. Canada is endowed with large unconventional gas resources, and with growing competition in North America, Canada's natural gas producers are examining global opportunities as they develop their plans to exploit these resources.

Current LNG consumers are mainly found among the energy-hungry economies of Asia, as well is in a number of the more developed Western European countries. Some LNG is also imported into North and South America. The Pacific Basin, which includes the economies of Asia, comprises the largest consuming region. It is also expected to exhibit the highest future growth rate, given the underlying strong economic growth of the countries in this region and their burgeoning demand for energy.

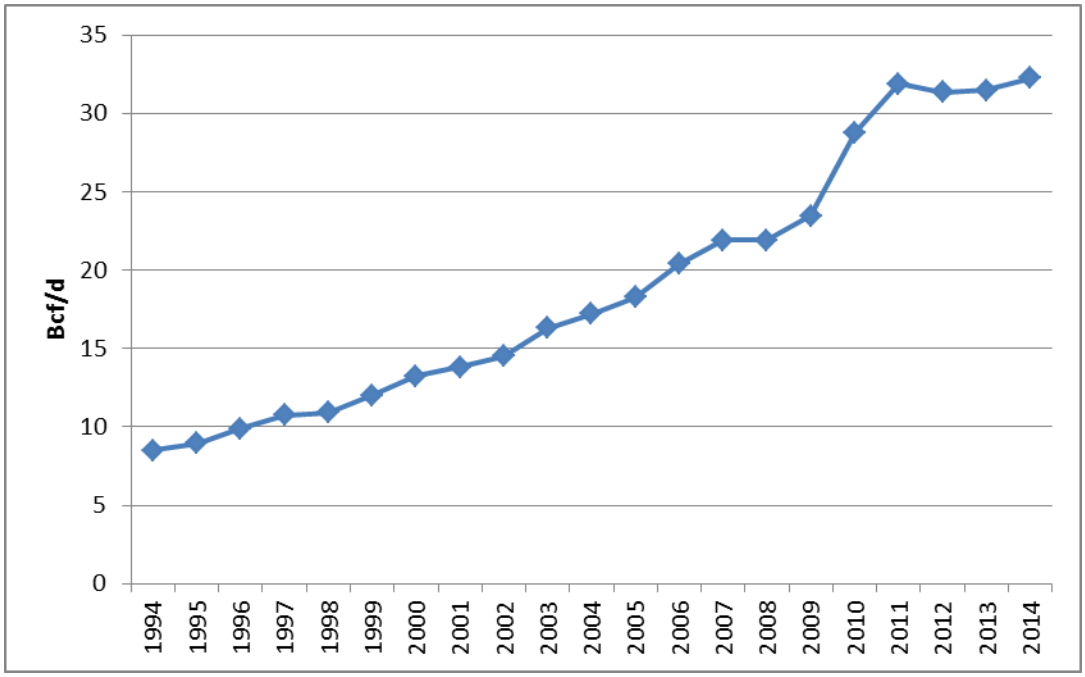
Competition for these growing markets will be fierce. An examination of all the gas liquefaction projects worldwide that are under construction or in the proposal stage shows there exists the potential to substantially increase worldwide liquefaction capacity within the next decade. In particular Australia, the United States and, to a lesser extent, Nigeria could emerge as significant LNG suppliers with Australia challenging Qatar as the world's largest LNG exporter.

Canada's potential participation in the LNG market is driven by a number of factors, most notably: the large resource base located near the country's West Coast; the proximity of Canada's West Coast to Asian markets; an infusion of foreign investment from countries that consume LNG; the need for Canadian producers to increase their market diversification; and the desire to access markets with higher netback potentials given the relatively low natural gas prices currently found in North America. On the East Coast of Canada the prospect for LNG exports is also emerging given its favourable location for serving European markets and the presence of a natural gas pipeline grid that provides access to growing North American production for feedstock for plants in this region.

2 Overview of the World LNG Market

World trade in LNG has more than tripled over the last 20 years, growing from 8.5 Bcf/d in 1994 to just over 32 Bcf/d in 2014. While growth has stalled in the last few years as the European market has struggled to emerge from recession, it is anticipated that the global LNG market will soon return to more rapid rates of expansion. This should occur as better upstream production technology means more gas reserves worldwide are available for development while demand for energy, particularly from less-emitting sources, is expected to grow. Canada is endowed with large unconventional gas resources, and producers in this country are paying more attention to the world LNG market potential as they develop plans to develop these resources.

Figure 1 - World LNG Trade (Bcf/d)



Source: BP Statistical Review of World Energy

The remainder of this overview identifies the main sources of LNG supply and the markets that currently consume LNG. It concludes with a general discussion of how LNG prices are established. Section 3 provides a more detailed analysis of each country that participates in the LNG market or has the potential to participate. It first examines countries that supply LNG before looking at countries consuming LNG. Section 4 provides an assessment of the drivers behind Canada's potential participation in the LNG market and what impact the entry of Canada might have.

2.1 World LNG Supply

The current suppliers of LNG to world markets and those expected to emerge as significant suppliers come, not surprisingly, from countries endowed with the largest natural gas reserves. Table 1 (below) identifies the 20 countries with the largest known conventional gas reserves measured in trillions of cubic feet (Tcf).

Table 1 - World Conventional Natural Gas Reserves by Country as of December 31 2014 (Tcf)

	World	*6606*
	Top 20 Countries	6079
1	Iran	1201
2	Russian Federation	1153
3	Qatar	866
4	Turkmenistan	617
5	US	345
6	Saudi Arabia	288
7	United Arab Emirates	215
8	Venezuela	197
9	Nigeria	180
10	Algeria	159
11	Australia	132
12	Iraq	127
13	China	122
14	Indonesia	101
15	Canada	72
16	Norway	68
17	Egypt	65
18	Kuwait	63
19	Kazakhstan	53
20	Libya	53
	Rest of World	527

Source: BP Statistical Review

In addition to these conventional reserves, vast resources of unconventional gas are now being unlocked by improved technology. Advances in horizontal drilling and hydraulic fracturing mean that natural gas from shale formations, once considered uneconomic to produce, is now accessible for production. In 2015, the United States Potential Gas Committee increased its estimate of potential U.S. gas resources from 2,384 Tcf to 2,515

Tcf. This estimate includes 1,253 Tcf of shale gas resources which have grown tremendously from an assessed level of only 200 Tcf as recently as 2006 when total potential gas resources were estimated to be 1,321 Tcf. In June 2013, the U.S. Energy Information Administration (U.S. EIA) completed an assessment of world shale gas resources outside the United States. The report examined 137 shale formations in 41 countries outside the United States. It found there was the potential to recover 6,634 Tcf. Of this total, Canada comprised 573 Tcf.

Table 2 - World Shale Gas Resources Outside U.S. (Tcf)

	Risked Gas In-Place	***Technically Recoverable Resources***
North America (Canada, Mexico)	4,647	1,118
South America	6,390	1,431
Europe	4,895	883
Africa	6,664	1,361
Asia (China, India, Pakistan, Turkey)	6,495	1,403
Australia	2,046	437
Total	**31,138**	**6,634**

Source: US Energy Information Administration

With these large reserves of natural gas in place, the U.S. EIA is forecasting healthy growth in world natural gas production. As shown in Table 3 (below), world natural gas production is expected to increase from just over 300 Bcf/d in 2010 to 512 Bcf/d in 2040. Currently about 10 per cent of all natural gas production finds its way into the LNG market.

Table 3 - World Natural Gas Production by Region in the Reference Case, 2010-2040 (Bcf/d)

	Projections						
	2010	2015	2020	2025	2030	2035	2040
OECD							
OECD Americas	77.9	83.4	91.9	98.8	104.7	112.6	121.5
OECD Europe	28.6	24.7	22.1	21.9	23.5	25.3	27.2
OECD Asia	5.8	7.8	11.0	13.8	15.7	17.4	18.9
Total OECD	112.2	115.9	124.9	134.4	143.9	155.3	167.6
Non-OECD							
Non-OECD Europe and Eurasia	73.1	79.5	87.8	97.6	109.0	119.2	124.9
Non-OECD Asia	40.6	40.8	42.9	46.4	52.6	60.2	67.2
Middle East	43.5	55.2	62.3	69.0	75.3	80.6	86.2
Africa	20.2	22.0	25.5	28.1	30.8	34.0	37.3
Central and South America	14.8	17.6	20.2	21.7	23.3	26.0	28.6
Total Non-OECD	192.3	215.0	238.7	263.0	291.1	320.0	344.2
Total World	304.5	330.9	363.6	397.4	434.9	475.3	511.8

Source: EIA 2013 International Energy Outlook

As mentioned, it is not surprising that there is a high degree of correlation between countries with large natural gas reserves and those that are the largest LNG suppliers. Currently the countries located in the Pacific Basin that supply the largest volumes of LNG include Malaysia, Indonesia and Australia (see Table 4). As discussed later in this report, Australia has a number of LNG liquefaction projects both under construction and in the planning stages, which should see it emerge as a much more significant supplier. Also, the first exports of LNG from Russia have occurred with the completion of its Sakhalin II project, which is likely to be the first of several LNG liquefaction developments in this country.

Table 4 - Global LNG Supply (Bcf/d)

Exporter	*2011*	*2012*	*2013*	*2014*
Malaysia	3.22	3.10	3.26	3.30
Indonesia	2.82	2.40	2.18	2.10
Australia	2.51	2.70	2.92	3.10
Brunei	0.91	0.90	0.92	0.80
Russia	1.39	1.40	1.38	1.40
Alaska	0.2	0.10	0.01	0.04
Peru	0.5	0.50	0.54	0.60
Papua New Guinea	0.00	0.00	0.00	0.50
Total Pacific Basin	11.55	11.1	11.21	11.84
Qatar	9.92	10.20	10.27	10.00
Oman	1.06	1.10	1.11	1.00
Abu Dhabi	0.77	0.70	0.71	0.80
Yemen	0.86	0.70	0.93	0.90
Total Middle East	12.61	12.7	13.02	12.7
Trinidad	1.83	1.80	1.92	1.90
Algeria	1.66	1.50	1.45	1.70
Nigeria	2.5	2.60	2.17	2.40
Egypt	0.83	0.60	0.36	0.04
Norway	0.38	0.50	0.37	0.50
Equatorial Guinea	0.51	0.50	0.50	0.50
Libya	0.01	0.00	0.00	0.00
Total Atlantic Basin	7.72	7.5	6.77	7.04
Total World	31.88	31.30	31.46	32.2

Source: Oil and Gas Journal & BP World Energy Statistical Review

Of those countries located in and supplying markets in the Atlantic Basin, Trinidad, Algeria and Nigeria are currently the dominant suppliers. Nigeria, however, has a number of LNG liquefaction projects being planned and developed that should increase its relative significance as an LNG supplier.

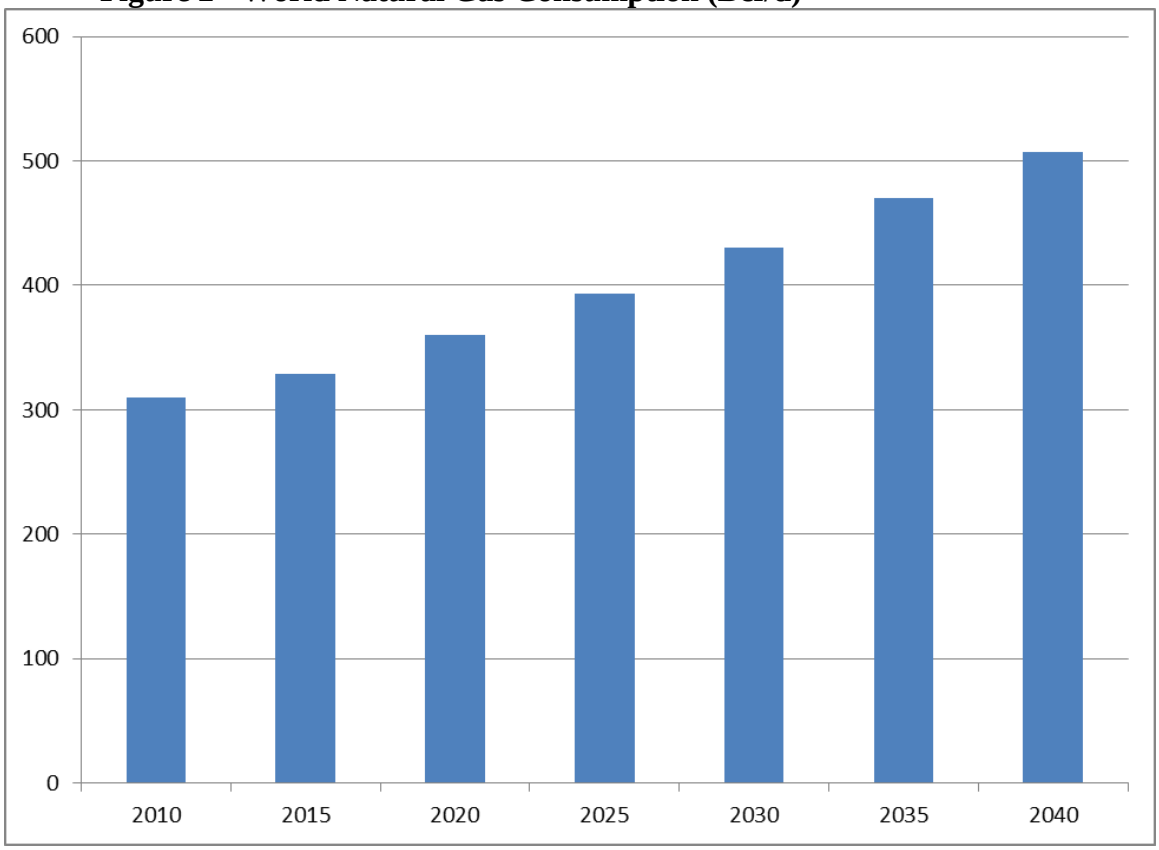
Exports of LNG from the Middle East are dominated by Qatar, the largest exporter of LNG in the world. This status, however, could be challenged by Australia over the next decade as this country has a considerable number of developed and planned LNG

projects. LNG exports from the Middle East serve markets in the Pacific and Atlantic basins.

2.2 World Demand for LNG

The Energy Information Administration is expecting worldwide natural gas consumption to increase from 310 Bcf/d in 2010 to 507 Bcf/d in 2040 (see Figure 2). Much of this increase is due to the anticipated growth in the use of natural gas for power generation as countries take advantage of the cleaner-burning properties of this fuel. Natural gas consumption is expected to grow considerably faster in developing countries than consumption in OECD countries. As global use of natural gas increases, the size of the LNG market will grow as well. While currently about 10 per cent of natural gas produced globally is liquefied, the LNG market will likely account for a growing share of world natural gas trade as global liquefaction capacity increases. (Chapter 3 contains information for the number of projects that have been announced globally that are in various stages of development).

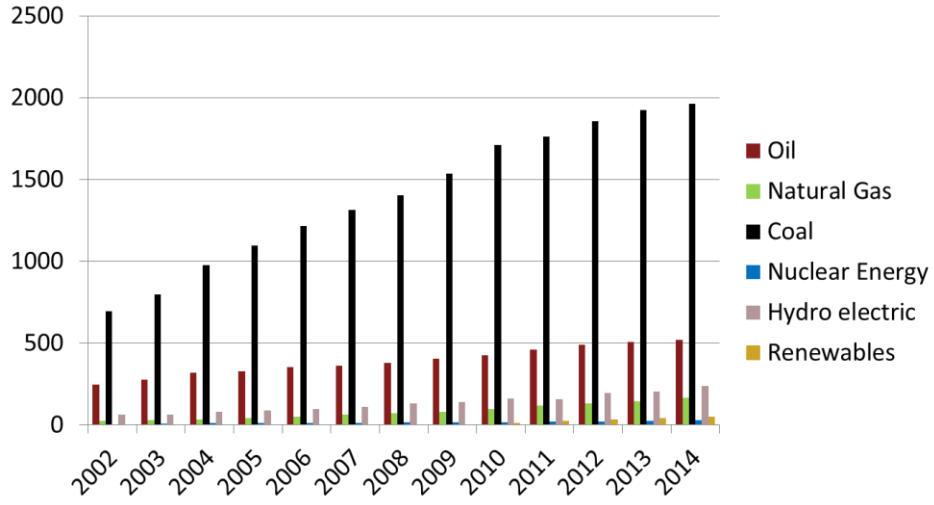
Figure 2 - World Natural Gas Consumption (Bcf/d)



source: EIA 2013 International Energy Outlook

Current LNG consumers are mainly found among the energy-hungry economies of Asia, as well as in a number of the more developed Western European countries. Some LNG is also imported into North and South America. The Pacific Basin is the largest consuming region and is also expected to exhibit the highest future growth rate given the underlying economic growth of the countries found in this region and their burgeoning energy demand. With respect to the Asian LNG importers, Table 5 shows that Japan is by far the largest importer in this region and in fact the world, with more than 30 LNG import terminals in service and several more being planned. Japan accounts for over 35 per cent of the worldwide LNG consumption and with the substantial damage to Japanese nuclear power generating capacity as a result of the 2011 tsunami, LNG imports have grown higher to compensate for the loss of nuclear power generating capacity. China recently emerged as a net importer of natural gas. With its almost insatiable demand for energy, it is expected to become a major LNG importer. Figure 3 shows that China has been meeting its increasing demand for energy primarily through increased coal use. However, with growing pressure to reduce smog in urban centers there exists a huge potential for natural gas, with its cleaner-burning properties, to help displace coal in China's power generation mix. The combination of high demand for energy and the need to reduce its reliance on coal means China has enormous potential for growth in LNG consumption. India is also expected to increase its demand for LNG.

Figure 3 – China Primary Energy Demand MTOE



The developed economies of Western Europe imported 5 Bcf/d of LNG in 2014, which is about half the level of imports in 2011, as the economies of the region continue to struggle. These nations are not expected to increase their demand for LNG anywhere near the same rate as the growing Asian economies. LNG is also consumed in the Americas,

but as will be discussed in the more detailed country analysis, the emergence of shale gas in North America means this region is more likely to become a net exporter of LNG rather than an importer.

Table 5 - Imports of LNG (Bcf/d)

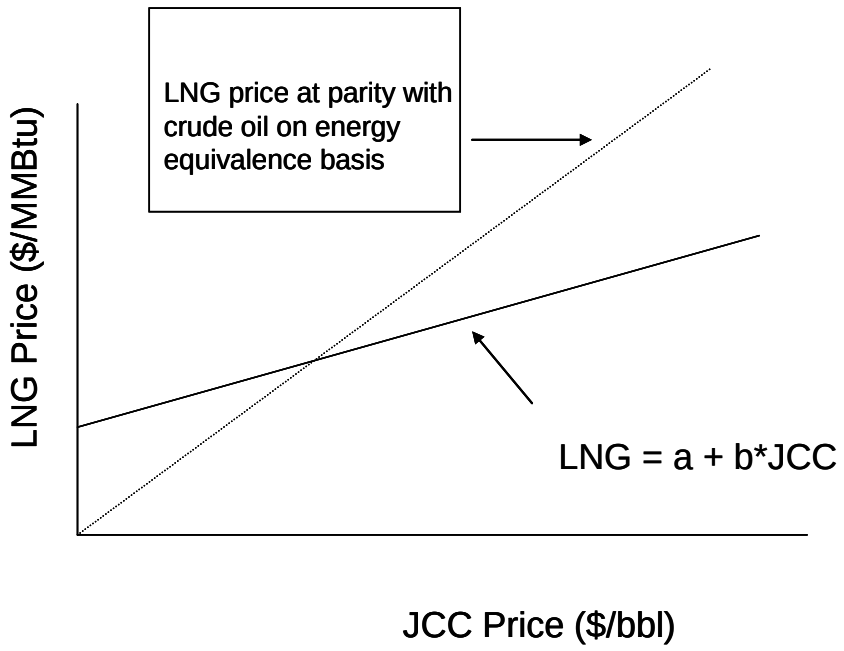
	2011	*2012*	*2013*	*2014*
France	1.41	1	0.85	0.70
Spain	2.34	2.1	1.45	1.50
Portugal	0.3	0.4	0.0	0.30
Turkey	0.6	0.7	0.59	0.70
Belgium	0.64	0.4	0.31	0.30
Italy	0.85	0.7	0.54	0.40
Greece	0.13	0	0	0.00
UK	2.45	1.3	0.90	1.10
US	0.97	0.5	0.27	0.20
Puerto Rico	0.07	0	0	0
Dom. Republic	0.09	0	0	0
Mexico	0.39	0.5	0.76	0.90
Brazil	0.1	0.3	0.49	0.80
Argentina	0.42	0.5	0.67	0.60
Chile	0.37	0.4	0.40	0.40
Canada	0.32	0.20	0.10	0.10
Kuwait & United Arab Emirates	0.43	0.4	0.44	0.50
Total Atlantic Basin & Americas	11.88	9.4	7.77	8.5
Japan	10.34	11.5	11.57	11.70
South Korea	4.77	4.8	5.27	4.90
Taiwan	1.58	1.6	1.66	1.70
India	1.65	2	1.72	1.80
China	1.61	1.9	2.38	2.60
Total Pacific Basin	19.95	21.8	22.60	22.7
World Total	31.83	31.2	31.46	32.2

Source: BP World Energy Statistical Review

2.3 Pricing of LNG

Given the capital-intensive nature of liquefaction projects, long-term ship or pay contracts are used to ensure high utilization rates and to meet investment hurdle rates. In Asia almost all LNG is sold under long-term contracts based on oil prices. In Japan, contracts are linked to the Japanese Customs Cleared (JCC) price for crude oil which is the price of a basket of crude oil types imported in Japan that is tracked by the Japanese government. The chart below shows a typical price structure for LNG negotiated on the basis of the JCC. Thus for example, with a security of supply premium of $0.5/MMbtu (shown as **a** in Figure 4) and an LNG slope of JCC of 0.15, (shown as **b** in Figure 4) this would result in an LNG price of $15.50/MMbtu if the JCC price was $100 per barrel.

Figure 4 - Typical JCC Structured LNG Pricing Contract



More recently Henry Hub-linked contracts have emerged in Asia as an alternative pricing formula.[1] This occurred when global oil prices hovered around levels of US$100 barrel or more and some importers were consequently looking for alternatives to the traditional pricing methodology. Considerable debate among market observers took place as to whether there would be a significant move away from the current trend of oil-indexed long-term LNG contracts in Asia. Some observers contended that the majority of suppliers would still prefer oil-indexation because of the transparency, reliability and traditional acceptance by all players. The recent decline in crude oil prices has

[1] In late 2011, Cheniere Energy Partners announced it had signed commercial arrangements with several customers at its Sabine Pass LNG project that involve a fixed capacity charge to cover the costs of liquefaction and then to buy LNG at 115 per cent of the Henry Hub natural gas price.

dramatically reduced the landed cost of LNG sold in Asia based on an oil index, and Asian customers have been less vocal about revising contractual pricing methodologies as a result. Indeed with today's weaker outlook for oil prices these particular contracting practices may present more challenges to suppliers looking to serve these markets while generating adequate investment returns.

In the case of the global LNG market, over the past few decades suppliers have been challenged to keep up with the pace of demand. LNG consumers have placed a premium on security of supply and have been willing to sign up for long-term contracts. LNG suppliers have in turn sought long-term contracts to underpin the large capital investments involved. As a result, to date the spot market for LNG has been limited compared to the size of the market overall.

This trend could change if those countries that are aggressively seeking to expand their LNG liquefaction capacity create surplus of supply in world LNG markets. More intense gas-on-gas competition would see the emergence of a larger spot market with less volumes being sold on a long term basis with prices linked to those of crude oil. Australia alone has a series of LNG export projects in various stages of development that could increase this country's export capacity from 2.5 Bcf/d today to over 16 Bcf/d in 2018. Thus if the anticipated high rates of growth in demand in the emerging economies of China and India fail to take place as anticipated, a surplus of supply of LNG would translate into a more significant spot market with prices reflecting greater gas on gas competition and less linkage to oil prices.

3 LNG Supply and Demand Outlook

As discussed in Section 2, there are a large number of countries that currently participate as suppliers or consumers in the worldwide LNG market. Even more countries are expected to participate as new sources of supply are developed and additional countries seek to rely on the cleaner-burning properties of natural gas to meet their energy needs. This section begins by looking at the outlook for new liquefaction capacity that is expected to add to the world's supply of LNG. The section concludes by examining more closely those countries that currently consume LNG and their prospects for future growth.

Figure 5 –Global Liquefaction Capacity Existing & Under Construction (Bcfd)

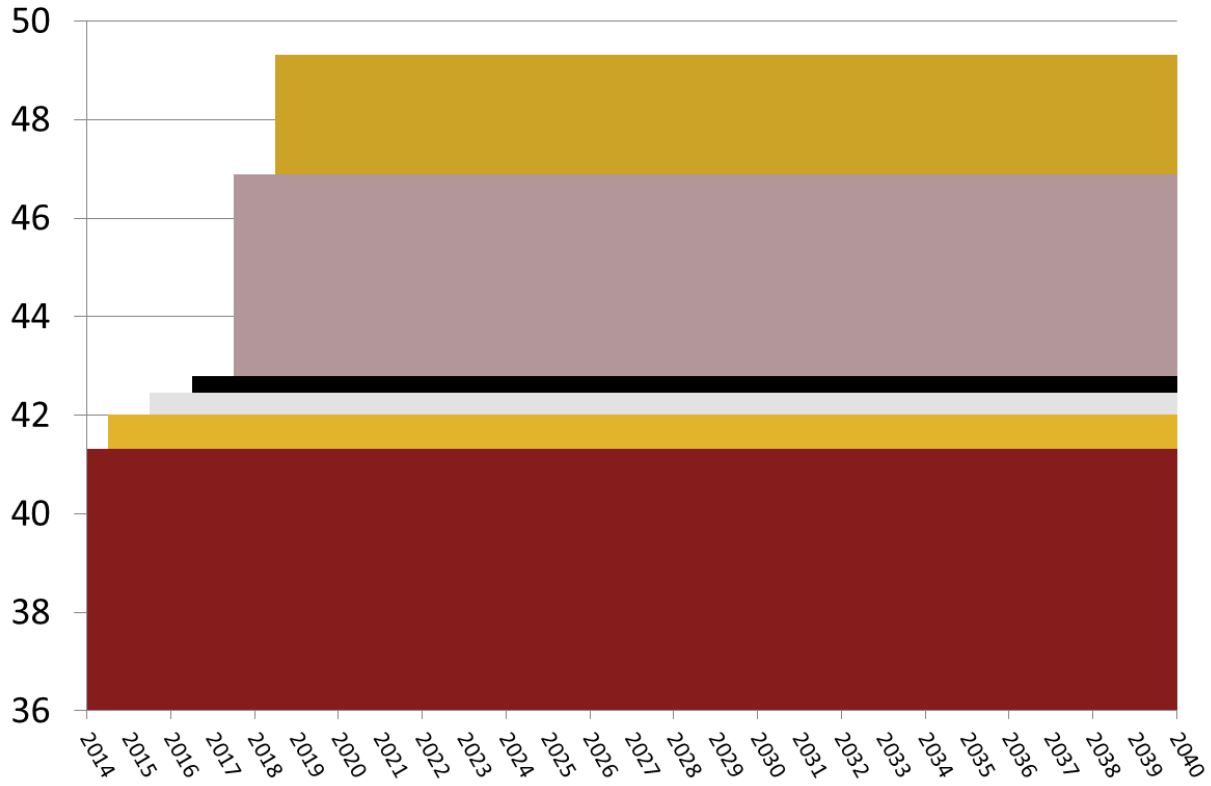


Figure 5 shows that in 2014, global liquefaction capacity was about 41 bcfd. A number of projects are under construction that would increase this capacity to almost 50 bcfd by 2018. Table 6 shows that most of these projects currently under construction are located in Australia and the US.

Table 6 - World LNG Liquefaction Capacity Under Construction (Bcf/d)

Country	LNG Export Facility	Start up	Capacity Bcfd
Australia	Queensland Curtis LNG T2	2015	0.57
Colombia	Pacific Rubiales	2015	0.07
Indonesia	Donggi-Senoro LNG	2015	0.27
Malaysia	PETRONAS LNG 9	2015	0.48
Australia	Australia Pacific LNG T1	2015	0.60
Australia	Australia Pacific LNG T2	2015	0.60
Australia	Gladstone LNG T1	2015	0.52
Malaysia	PETRONAS FLNG	2015	0.16
US	Sabine Pass T1	2015	0.60
Australia	Gorgon LNG T1	2015	0.69
Australia	Gorgon LNG T2	2015	0.69
Australia	Gorgon LNG T3	2016	0.52
Australia	Wheatstone LNG T1	2016	0.60
US	Sabine Pass T2	2016	0.60
US	Sabine Pass T3	2016	0.60
Australia	Prelude LNG (Floating)	2016	0.48
Australia	Ichthys LNG T1	2016	0.56
US	Sabine Pass T4	2017	0.60
Australia	Wheatstone LNG T2	2017	0.60
Australia	Ichthys LNG T2	2017	0.56
Russia	Yamal LNG T1	2017	0.73
Russia	Yamal LNG T2	2018	0.73
US	Cameron LNG T1	2018	0.53
US	Cameron LNG T2	2018	0.53
Malaysia	Rotan FLNG	2018	0.20
US	Freeport LNG T1	2018	0.59
US	Cove Point LNG	2018	0.77
Russia	Yamal LNG T3	2019	0.73
US	Cameron LNG T3	2019	0.53
US	Freeport LNG T2	2019	0.59
US	Freeport LNG T3	2019	0.59

3.1 LNG Supply as a Function of World Liquefaction Capacity

Qatargas, established in 1984, pioneered the LNG Industry in Qatar. Today, Qatargas is the largest LNG-producing company in the world, with an annual LNG production capacity of 42 million tonnes per annum (MTA), or 5.6 Bcf/d. Qatargas has seven LNG trains, of which four are the largest in the world with a production capacity of 7.8 MTA (1.04 Bcf/d) each. A second company, RasGas, oversees and manages the operations associated with a further seven LNG trains in Qatar, for which it has a total production capacity of approximately 37 million tonnes per annum (4.9 Bcf/d). Much of this development has come on stream in recent years so that with a total of 79 million tonnes per annum (10.5 Bcf/d) of LNG capacity, Qatar has emerged as the world's leading LNG producer and exporter.

A closer examination of Table 6, which shows the projects worldwide that are under construction, reveals that in particular Australia, and to a lesser extent the U.S., will emerge as significant LNG suppliers, with Australia challenging Qatar's status as the world's largest LNG exporter. The prospects for LNG exports from the U.S. are discussed in more detail in section 3.28 of this report.

Australia's North West Shelf LNG project has been in service since 1989 and has now grown to five trains that have a combined liquefaction capacity of 2.14 Bcf/d. As a result of several new natural gas discoveries, there has in recent hears been considerable activity with respect to developing new LNG production projects in Western Australia. These include:

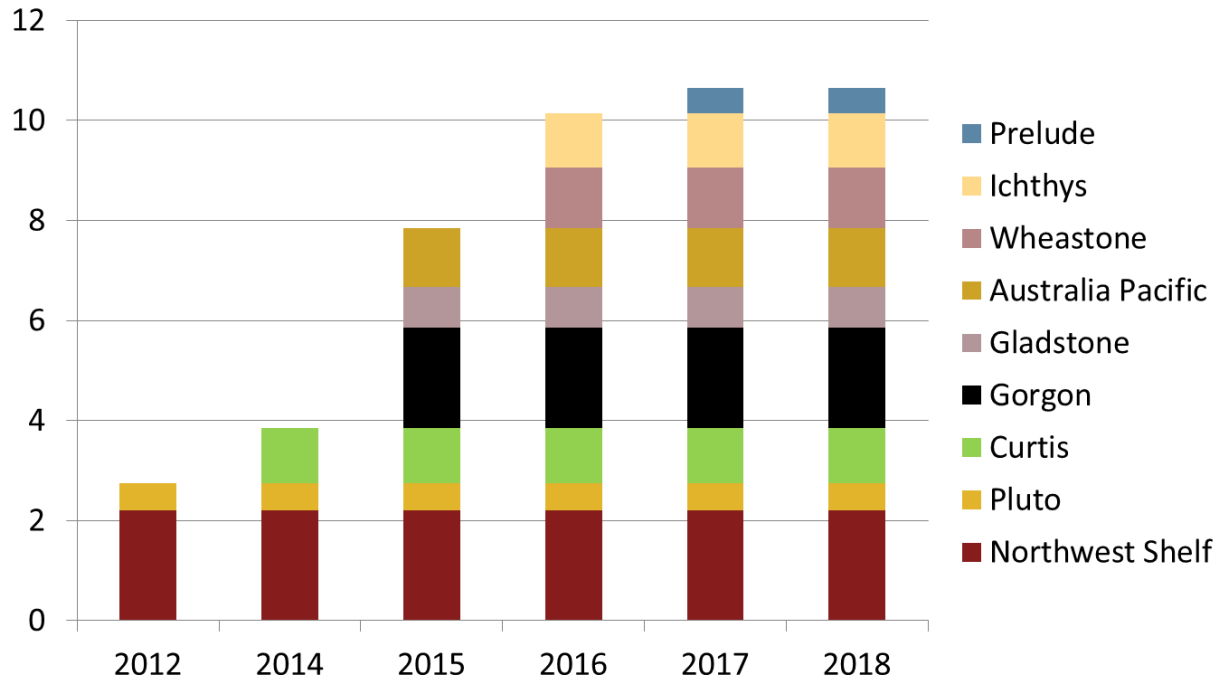
- The Pluto project near Karratha, offshore Western Australia. Woodside Energy owns 90 percent of the venture supported by 15-year contracts with Kansai Electric and Tokyo Gas at five per cent equity each. The project includes an offshore platform connecting five subsea wells and a 112-mile pipeline to an onshore LNG facility on the Burrup Peninsula. The first train came online in 2012 with a capacity of 0.55 Bcf/d.
- The Gorgon project, led by Chevron (50 per cent), with Shell and ExxonMobil (25 per cent each), which is under construction. The Gorgon gas field, which is 80 to 124 miles off the northwest coast, is believed to contain 40 Tcf of natural gas and is Australia's largest known natural gas resource. The project includes development of the Gorgon gas fields with subsea pipelines to Barrow Island; a gas processing facility on the island with production capacity of 2.05 Bcf/d, consisting initially of three 0.68 Bcf/d LNG trains; LNG shipping facilities to transport products to international markets; and greenhouse gas management via injection of carbon dioxide into deep formations beneath Barrow Island. The Gorgon joint venture is investing approximately $2 billion in the design and construction of the world's largest commercial-scale CO_2 injection facility to reduce the project's overall greenhouse gas emissions by between 3.4 and 4.1 million tonnes per year. The project is expected to be in service by Q4 2015.

- The Ichthys projectis led by Japan's INPEX (74 per cent) and Total (26 per cent), located offshore the northwest coast in the Browse Basin. It is expected to produce LNG, liquefied petroleum gas (such as propane and butane) and condensate for export to Japan and elsewhere via a 528-mile undersea pipeline connecting the fields to a new LNG export terminal to be built near Darwin. When the project comes onstream in 2016, its production is expected to be at least 1.1 Bcf/d.
- The Wheatstone project, which is under construction. Its largest owners are Chevron (64 per cent) and Apache (13 per cent). Sales and purchase agreements have been signed with Tokyo Electric Power Company and Kyushu Electric Power Company. The first stage of the project consists of two trains with a combined capacity of 1.2 Bcf/d. However, the project has approval to expand to 3.28 Bcf/d. Wheatstone is expected to go into service in 2016.
- In May 2011, Shell announced it has taken the final investment decision to proceed with its Prelude Floating Liquefied Natural Gas (FLNG) Project in Australia. Moored some 200 kilometres from the nearest land in Australia, the FLNG facility will produce gas from offshore fields and liquefy it onboard the same facility. Shell retains a 67.5 per cent interest in the project, while Inpex has a 17.5 per cent interest, Kogas has 10 per cent and CPC has five per cent. The FLNG facility will tap around three Tcf equivalent of resources contained in the Prelude gas field. Shell discovered the Prelude gas field in 2007. Expected production from Prelude is 5.3 million tonnes per annum (mtpa) of liquids, comprising 3.6 mtpa of LNG (0.47 Bcf/d), with the remaining output consisting of condensate and liquefied petroleum gas.

These projects are not only competing with each other but also with three significant coal seam-gas-LNG projects in the eastern Australian state of Queensland. These projects include:

- Australia Pacific LNG, sponsored by Origin Energy, Sinopec and ConocoPhilips. This project will consist of two trains with a combined production capacity of 1.18 Bcf/d. First LNG exports are anticipated in 2015
- Gladstone LNG, sponsored by Santos, Petronas, Kogas and Total. This project consists of two trains with a combined capacity of 0.82 Bcf/d. First cargoes are expected to be shipped by 2015
- Queensland Curtis, sponsored by BG, will in its first stage consist of two trains with a combined capacity of 1.11 Bcf/d. LNG deliveries is commenced in 2014. The project can be expanded to three trains to obtain a total of 1.6 Bcf/d of capacity.

Figure 6: Australian Liquefaction Projects (Bcf/d)



Nigeria, one of the larger LNG exporters, also plans to significantly increase its production. Its output comes from the Nigeria Liquefied Natural Gas (NLNG) facility on Bonny Island. This facility has six trains in operation, but plans for building a seventh train that would lift total production capacity to over 30 Million tonnes per annum (4.2 Bcf/d) are at an advanced stage. Additional future projects include Brass LNG, a project owned by Nigerian National Petroleum Corporation (NNPC) with Total, and ENI also having equity shares. The project proposes to have two trains with a total capacity of 10 million tonnes per annum (1.4 Bcf/d). The exit of ConocoPhillips from the consortium in 2014, however, has delayed a final investment decision. Another project is OKLNG, which involves the development of a green field export facility for LNG in the Olokola area of Ondo/Ogun States in western Nigeria. It involves the development of a 25.2 mtpa (3.3 Bcf/d) LNG export facility commencing with a two (2) train first phase launch of 12.6mtpa (1.7 Bcf/d) and expandable to 40 mtpa (5.3 Bcf/d). An in-service date has yet to be announced.

Russia is also pursuing developments that would expand this country's capacity to export LNG. Its Sakhalin 2 project came on stream in 2009 and now consists of two trains with a combined export capacity of 1.3 bcfd. Yamal LNG is currently under construction and will comprise three trains with a combined capacity of 2.2 bcfd. The first train is expected to start service in 2017. This project is being developed by Novatek, Total and CNPC. Other projects in much earlier stages of development include Rosneft's Pechora

LNG and Far East LNG projects. Gazprom is also proposing to add a third train to its Sakhalin 2 project and is considering plans for two additional projects, namely Vladivostok LNG in the Russian far east and Baltic LNG in the northwest of the country. Sanctions currently imposed on Russia may have a negative impact on the timing of these projects.

With the potential for such a marked increase in LNG supply on the horizon, it is important to examine the prospects for world demand to soak up these incremental supplies. The continuation of significantly higher prices being realized today on world LNG prices compared to their North American counterparts will hinge, in large part, on the ability of world demand growth to keep up with the additional supplies being forecast. The remainder of this section looks more closely at the countries that import LNG today and those expected to import LNG to assess the prospects for world LNG demand growth.

3.2 Major Importers of LNG

3.2.1 Japan

Japan has very limited domestic supplies of natural gas, and as a populous country with a highly developed economy, it has emerged as the world's largest consumer of LNG.

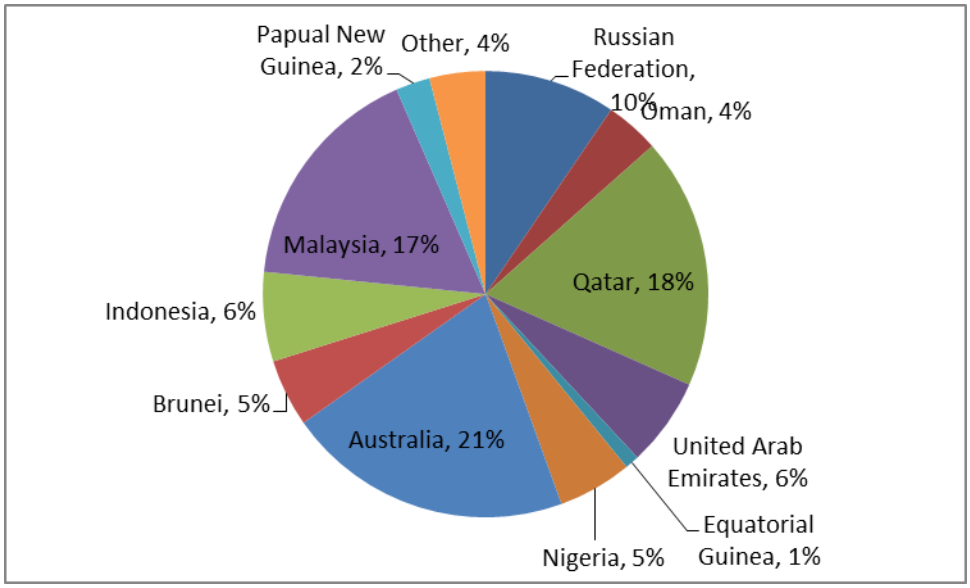
INPEX and other companies created from the former Japan National Oil Company are the primary players in Japan's domestic natural gas sector, as in the oil sector. INPEX, Mitsubishi, Mitsui and various other Japanese companies are involved in domestic as well as overseas natural gas exploration and production. Osaka Gas, Tokyo Gas, and Toho Gas are Japan's largest retail natural gas companies, with a combined share of about 75 per cent of the retail market. Japanese retail gas and electric companies are participating directly in overseas upstream LNG projects to assure reliability of supply.

Japan began importing LNG from Alaska in 1969, making it a pioneer in the global LNG trade. Due to environmental concerns, the Japanese government has encouraged natural gas consumption in the country, and Japan currently accounts for approximately 37 per cent of global LNG imports. Prior to 2011 the country was importing about 9 Bcfd. The increase in imports after 2011 to levels greater than 11 Bcfd is a direct result of the March 2011 earthquake and the resulting need to import more spot LNG along with other fuels to cover the nuclear power outages. Only one small regasification terminal, Shin Minato LNG, shut down as a result of the earthquake, allowing the country to continue importing LNG and compensate for some portion of lost nuclear capacity.

The power sector is the largest consumer of LNG, followed by the industrial sector. Increased use of natural gas within these sectors has been one of the main drivers of growth of natural gas demand in Japan.

Japan has over 30 operating LNG import terminals with a total throughput capacity well in excess of historical levels of demand to assure flexibility. The majority of Japan's LNG terminals are located in the main population centers of Tokyo, Osaka and Nagoya, near major urban and manufacturing hubs, and are owned by local power companies, either alone or in partnership with gas companies. These same companies own much of Japan's LNG tanker fleet.

Figure 7 - Japan Imports by Source, 2014



Other: includes Peru, U.S., Trinidad, Algeria, Egypt, Yemen, Angola, Norway

Source: BP Statistical Review

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. Some industry analysts suggest this is driving Japanese firms' interest in acquiring equity stakes in foreign LNG projects in an effort to guarantee future supply. In addition to long-term contracts, Japan receives a significant number of spot cargoes.

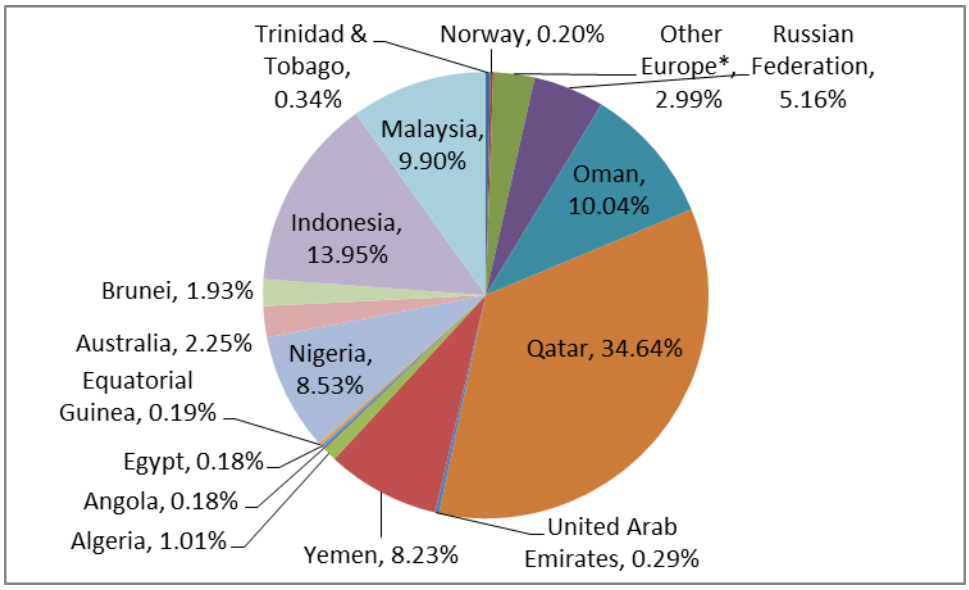
Contracted imports, however, remain vital to the country, which has led to the renegotiation of long-term supply deals, especially with Indonesia, one of Japan's largest LNG suppliers. Japanese companies are also involved as partners or customers of a number of new LNG projects that are being developed around the world as the country

seeks to diversify its sources of LNG supply. In 2014 Australia emerged as the largest supplier of LNG to Japan.

3.2.2 South Korea

With the recent completion of the Samcheok receiving facility on South Korea's northwest coast there are now five regasification facilities in South Korea, with a total capacity of 7.65 Bcf/d. KOGAS operates four of these facilities (Pyongtaek, Incheon,Tong-Yeong and Samcheok), accounting for more than 97 per cent 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 2014, South Korea imported 4.9 Bcf/d of LNG. KOGAS purchases most of its LNG through long-term supply contracts and uses spot cargos primarily to correct small market imbalances. About 70 per cent of 2014 natural gas imports came from Qatar, Malaysia Oman and Indonesia.

Figure 8 - South Korea LNG Imports by Source 2014



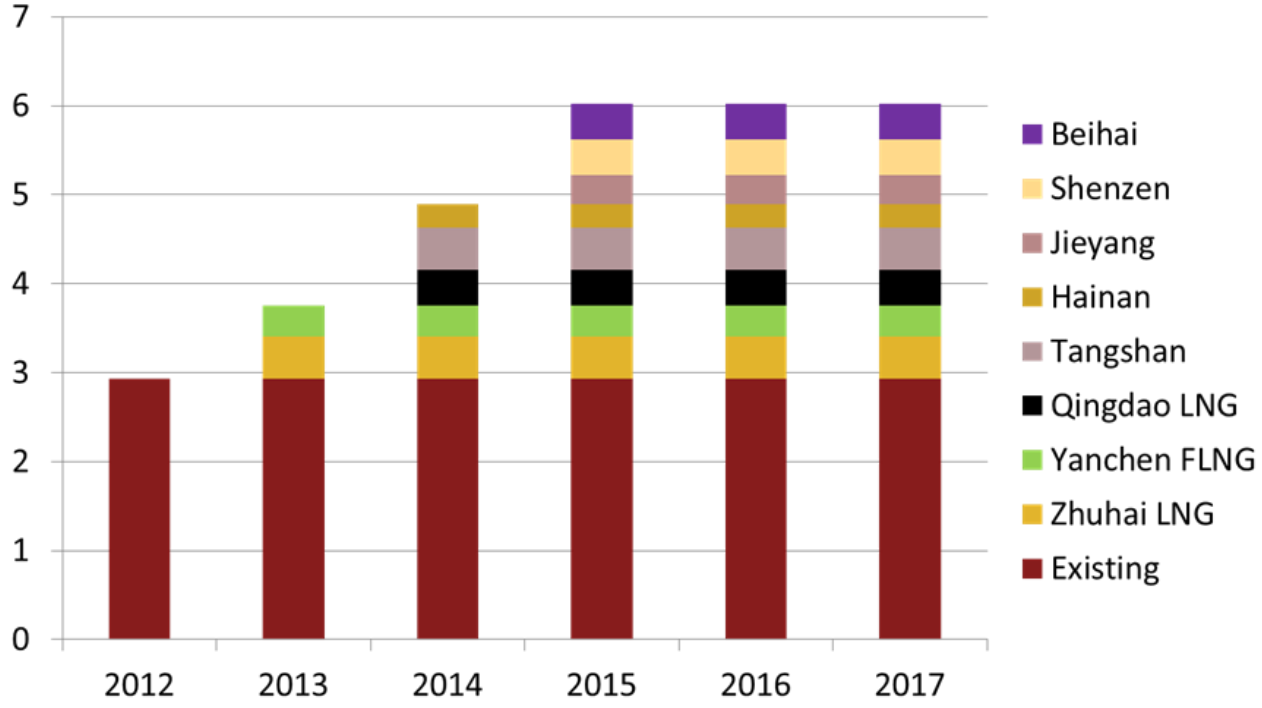
Source: BP Statistical Review

3.2.3 China

China began imports of LNG with the completion of its Guandong LNG terminal that became operational in 2006. Since that time a number of other LNG terminals have become operational, including Shanghai LNG, Fujan LNG, Rudong LNG and Dalian LNG. By 2012 the total import capacity of these facilities was 2.9 Bcf/d, and in that year China imported 1.93 Bcf/d of LNG. As shown in Figure 9, China has been constructing

additional LNG facilities so that by the end of 2015 the capacity for LNG imports is expected to exceed six Bcf/d. In 2014, LNG imports to China had grown to 2.6 Bcf/d.

Figure 9: Chinese Regasification Capacity: Existing and Under Construction (Bcf/d)



The above chart does not include expansion capacity that would be added through additional phases to the Rudong, Dalian and Tangshan LNG facilities as the timing for these expansions has yet to be confirmed.

In addition to developing these LNG import terminals, China has also invested in long-terms sales contracts for LNG with a number of global suppliers. Given these developments it is clear that Chinese imports of LNG will increase, but the ultimate level of such imports will depend heavily on a number of other factors. These include the success China may have in developing its own considerable reserves of natural gas which include 124 Tcf of proven reserves, while technically recoverable shale gas resources have been estimated by the EIA to amount to 1,115 Tcf .

In addition to domestic production, China has the opportunity to import gas via pipeline and currently imports about two Bcf/d of gas via pipeline from the giant Galkynysh field in Turkmenistan. In 2008, China National Petroleum Corporation (CNPC) and Turkmengaz signed a sales agreement that targeted an import volume of 3.8 Bcf/d of gas by 2015. The two companies have since signed a contract for additional supplies of 2.41 Bcf/d as further stages of the Galkynysh field are developed.

In August 2013, after three years of construction, the Myanmar-China natural gas pipeline started deliveries. The 793 km pipeline starts at Kyaukpyu on Myanmar's western coast and enters southwestern China's Yunnan province. The pipeline, when operating at capacity, will be capable of delivering as much as 1.2 Bcf/d of natural gas to China.

In March 2013, Russia signed a preliminary gas supply deal with China, comprising a framework whereby Gazprom would supply 3.7 Bcf/d of gas for 30 years commencing in 2018, which would eventually rise to as much as 5.8 Bcf/d. In May 2014 the terms of the deal, including price, were finalized in a signing ceremony held in Shanghai.

Despite having a variety of supply options, LNG imports to China are expected to grow, particularly as new LNG import infrastructure is currently under development. Over the past decade Chinese energy demand has almost tripled, and its heavy traditional reliance on coal is not sustainable as has come with a considerable environmental cost. Air pollution in Beijing has been reaching dangerous levels. The Chinese government has recently issued an Atmospheric Pollution Prevention Action Plan which targets a peak in coal consumption by 2017 and to reduce the level of air particulates by up to 25 per cent. As part of this initiative, the government plans to ban new coal-fired power plants in provinces surrounding Beijing, Shanghai and Guangzhou. China's most recent five-year plan (extending from 2011 to 2015) aims to cut the amount of energy and carbon dioxide emissions per unit of economic output by 16 per cent and 17 per cent respectively over the duration of the plan. Displacement of coal-fired power plants with natural gas-fired power plants would aid the country in meeting these targets, given the much lower emission rates of natural gas compared to coal. As a result, the Chinese government anticipates boosting the share of natural gas as part of total energy consumption to 10 per cent by 2020 to alleviate high pollution from the country's heavy coal use and diversify the fuel mix in all end-use sectors.

Taking into account these ambitious targets for increasing the natural gas share of China's overall energy mix, the EIA is forecasting growth in natural gas consumption in China of 360 per cent, from 10.4 Bcf/d in 2010 to 47.9 Bcf/d in 2040.

3.2.4 Taiwan

Taiwan's consumption of natural gas is projected to increase to 1.8 Bcf/d by 2020 and 2.1 Bcf/d by 2025, up 55 per cent and 77 per cent respectively, from 1.17 Bcf/d in 2009, according to its Bureau of Energy, Ministry of Economic Affairs, as it strives to cut its coal requirements. Regasified natural gas from LNG imports provides the vast majority of Taiwan's natural gas, while domestic supply provides only a minimal amount. In 2014 the country imported 1.7 Bcf/d of LNG. The main consumers of Taiwan's natural gas are its eight power generators that account for a combined total of 78.4 per cent, with the outstanding amount taken by energy (3.9 per cent), industrial (7.5 per cent), services (three per cent) and residential (7.2 per cent) users.

The government-owned Chinese Petroleum Corporation (CPC), which operates under the Ministry of Economic Affairs, controls all aspects of natural gas supply in Taiwan, including exploration, production, imports and wholesale sales. CPC constructed and operates two LNG terminals. The Yungan LNG receiving terminal in southern Taiwan has an official handling capacity of 1.02 Bcf/d a day. CPC has also constructed a second receiving terminal and associated infrastructure in Taichung in Taiwan's north. The receiving terminal has a capacity of 0.4 Bcf/d. An increase in the country's liquefaction capacity will be required to meet its gas consumption goals.

3.2.5 India

In 2014, India imported 1.8 Bcf/d of LNG, with over 90 percent of it coming from Qatar. India imports LNG through long-term contracts and spot shipments.

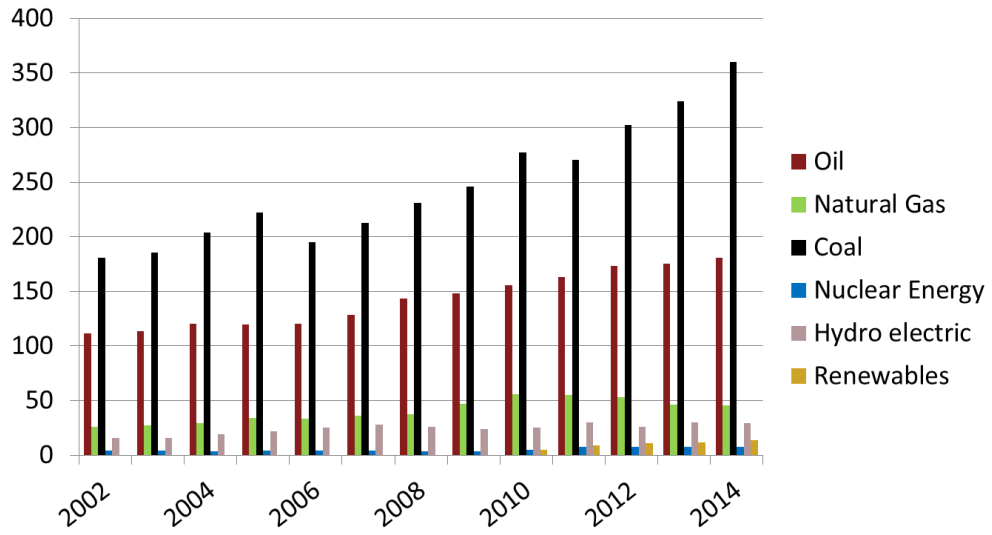
India now has four operational LNG import terminals: Dahej, Hazira, the Dabhol terminal that became operational in early 2013 and the recently commissioned Kochi terminal. India received its first LNG shipments in January 2004 with the startup of the Dahej terminal in Gujarat state. Petronet LNG, a consortium of state-owned Indian companies and international investors, owns and operates the Dahej LNG facility with a capacity of five million tons per year (mtpa) (0.65 Bcf/d). India's second terminal, Hazira LNG, started operations in April 2005 and is owned by a joint venture of Shell and Total. The facility has a capacity of 2.5 mtpa (0.3 Bcf/d), which may be expanded to five mtpa (0.65 Bcf/d).

The five mtpa (0.65 Bcf/d) LNG processing plant in Dabhol was recently commissioned, but the new facility will not be building up to full capacity quickly. A protective outer breakwater that will deflect ocean swells, especially during the June-September monsoon season, is still under construction and will not be ready until 2016. Until that time the terminal will not be able to be operated beyond 60 per cent of its rated capacity, i.e. a maximum three million tonnes per annum out of its five million tonnes per annum potential.

The Kochi terminal has a capacity of five MMTPA and was commissioned in January 2014. The facility has secured a 1.5 mtpa (0.20 Bcf/d) supply from Australia's Gorgon LNG project.

India has significant potential for growth in LNG imports. Figure 10 shows that primary energy demand in this country has been growing rapidly but to date, as has been the case in China, much of this growth in demand has been met by coal. While there is existing capacity to replace some coal by gas in the power generating mix, the challenge is for generators to recover the relatively higher costs of imported LNG with low end-user electricity prices.

Figure 10 – India Primary Energy Demand MTOE



Source: BP Statistical Review of World Energy

3.2.6 United Kingdom

The U.K. had been emerging as a significant importer of LNG as domestic natural gas supplies declined and imports of LNG peaked at 2.45 Bcf/d in 2011. Imports have declined since, however, as the economy struggled to avoid recession, which resulted in weak consumption growth in natural gas. Imports of LNG were 1.1 Bcf/d in 2014 but are projected to increase as the U.K. faces a need to fill gas storage and to offset persistent declines in domestic production.

Currently, the U.K. has four LNG import terminals. The longest-operating LNG terminal in the U.K. is National Grid's Grain LNG terminal on the Isle of Grain. The facility became operational in 2005 when Phase I of the construction was completed. Phase II was completed in 2009 and Phase III in 2011. With the completion of Phase II, the terminal's capacity increased to 1.4 Bcf/d. With Phase III complete, National Grid has expanded the facility to 2 Bcf/d in time for the 2010/2011 winter. Construction works of Grain LNG Phase IV are currently underway and commercial operations are targeted to commence by winter 2016/17. The planned Grain LNG Phase IV will expand the total yearly import capacity of the Grain LNG Terminal by up to 0.8 Bcf/d.

Teesport LNG, operated by the U.S.-based Excelerate Energy, commenced commercial operation in February 2007. This was the first dockside regasification port and the second

operational LNG facility in the U.K. Teesport LNG can deliver up to 0.60 Bcf/d of natural gas to the UK market.

The Dragon LNG terminal, a collaboration of BG, Petronas and 4Gas, commenced operation in September 2009. The import, storage and regasification terminal is located in Milford Haven in South Wales and has a sendout capacity of 0.8 Bcf/d.

The South Hook LNG terminal, also located in Milford Haven, is owned and operated by Qatar Petroleum, ExxonMobil and Total. Now that Phase II is completed, the facilities are capable of sending out two Bcf/d of gas to the U.K. national grid.

3.2.7 Other Western Europe

Spain has traditionally been Europe's largest LNG importer, with six LNG import terminals capable of regasifying up to five Bcf/d. As recently has 2011, Spain imported as much as 2.34 Bcf/d. By 2014. However, Spanish LNG imports had fallen to 1.5 Bcf/d as the economy struggled to recover from weak demand associated with the recession and growing competition from the startup of the Medgaz pipeline, which can bring 0.8 Bcf/d of gas from Algeria to Spain.

France has three LNG import terminals that can regasify 2.25 Bcf/d of LNG. In 2014 France imported 0.7 Bcf/d of LNG, which is about half of what it imported in 2011. Belgium has one LNG terminal that can regasify 0.9 Bcf/d of LNG, and in 2014 Belgium imported 0.3 Bcf/d. Both France and Belgium are well supplied by natural gas pipelines that compete with LNG facilities to meet these countries' natural gas needs.

Other significant European importers of LNG include Turkey, Italy, Portugal and Greece. In 2014, these countries combined imported 1.4 Bcf/d. None of these countries are anticipated to see a significant increase in LNG consumption.

3.2.8 North America

In Canada, the Canaport LNG terminal in Atlantic Canada commenced operation in 2009. This terminal, with a sendout capacity of one Bcf/d, exports natural gas to U.S. northeast markets. In recent years, however, exports have declined as the U.S. has become more reliant on growing domestic natural gas production to meet its needs.

Since the early part of the last decade there has been a flurry of construction of new import terminals in the U.S. as declines in conventional natural gas production created the perception that more LNG imports would be required to meet an anticipated energy shortfall. Table 7 below shows there are now 11 LNG import terminals in the U.S. with a combined capacity of 18.5 Bcf/d. However, the emergence of natural gas production from shale has reversed the decline in Lower 48-state gas production has reduced the need for LNG imports. This growth in domestic production caused a sharp U-turn in the development of LNG import infrastructure as natural gas producers were faced with the

prospect of finding new markets for their growing supplies and have since turned their attention to the prospect of exporting LNG. Despite its large import capacity, in 2013 U.S. LNG imports averaged only 0.26 bcfd. Indeed a number of existing import terminals sites have been transformed as brownfield developments for LNG export terminals.

Table 7 – Existing US LNG Import Terminals

Import Terminal	*Location/Size/Operator*	
A. Everett	MA : 1.035 Bcf/d (GDF SUEZ - DOMAC)	
B. Cove Point	MD : 1.8 Bcf/d (Dominion - Cove Point LNG)	
C. Elba Island	GA : 1.6 Bcf/d (El Paso - Southern LNG)	
D. Lake Charles	LA : 2.1 Bcf/d (Southern Union - Trunkline LNG)	
E. Offshore Boston:	0.8 Bcf/d (Excelerate Energy – Northeast Gateway)	
F. Freeport	TX: 1.5 Bcf/d(Cheniere/Freeport LNG Dev.)	Note: Has been authorized to re-export delivered LNG
G. Sabine	LA: 4.0 Bcf/d (Cheniere/Sabine Pass LNG)	Note: Has been authorized to re-export delivered LNG
H. Hackberry	LA: 1.8 Bcf/d (Sempra - Cameron LNG)	Note: Has been authorized to re-export delivered LNG
I. Offshore Boston	MA : 0.4 Bcf/d (GDF SUEZ – Neptune LNG)	
J. Sabine Pass	TX: 2.0 Bcf/d (ExxonMobil – Golden Pass) (Phase I & II)	
K. Pascagoula	MS: 1.5 Bcf/d (El Paso/Crest/Sonangol - Gulf LNG Energy LLC)	

Source: Federal Energy Regulatory Commission

Depending on location and use, an LNG facility may be regulated by several federal agencies and state utility regulatory agencies. The Federal Energy Regulatory Commission (FERC) is responsible for authorizing the siting and construction of onshore and near-shore LNG import or export facilities under Section 3 of the Natural Gas Act. The Natural Gas Act of 1938, as amended, requires that anyone who wants to import or export natural gas, including LNG from or to a foreign country, must first obtain an authorization from the Department of Energy (DOE). The Office of Oil and Gas Global Security and Supply, Division of Natural Gas Regulatory Activities is the relevant body to obtain these authorizations in the Department. The Natural Gas Act directs the DOE to grant LNG export authorizations to non-Free Trade Agreement (FTA) countries unless the Department finds that the proposed exports "will not be consistent with the public interest."[2] To date, the Department has approved seven such export licenses to Non-FTA countries.

The first project that obtained all regulatory approvals to export LNG from the U.S. is the Cheniere Energy facility at Sabine Pass, La. It obtained final FERC authorization in April 2012. The first four trains, with a combined capacity of 18 mtpa, are under construction, and while first LNG from Train 1 is anticipated in late 2015, it won't be until 2018 that all four trains will be in operation. The export terminal is being constructed on a brownfield site where the Sabine Pass LNG Import Terminal has been in operation since 2008.

In addition to being the first project to obtain regulatory approvals, Cheniere Energy also needed to finalize gas sales agreements to obtain financing to underpin the construction of its project. The structure of the commercial terms of the gas sales agreements has not followed the standard global industry practice of indexing the LNG price to crude oil but has indexed the price to North American gas prices instead. The first sale and purchase agreement (SPA) was entered into with a subsidiary of BG Group plc, under which BG has agreed to purchase 3.5 million tonnes per annum. Under the agreement, BG will pay Sabine Liquefaction a fixed sales charge of $2.25/MMbtu for the full annual contract quantity and will also pay a contract sales price for LNG purchases based on the applicable Henry Hub index traded on the New York Mercantile Exchange (115% HHI). The SPA has a term of 20 years. This template has been followed for subsequent contracts Cheniere Energy has negotiated with global customers, including some in Asia, for export capacity at the Sabine Pass facility.

Table 8 identifies those projects that have gone as far as to make an application to FERC for approval under Section 3 of the Natural Gas Act. These projects can be considered as having advanced from the preliminary or conceptual stage of development as substantial amounts of information are required, as well as considerable time and expense incurred

[2] Exports to countries that have FTA agreements are automatically deemed to be in the public interest. FTA agreements currently exist between the US and the following countries: Australia; Bahrain; Canada; Chile; Colombia; Costa Rica; Dominican Republic; El Salvador; Guatemala; Honduras; Israel; Jordan; Korea; Mexico; Morocco; Nicaragua; Oman; Panama; Peru; and Singapore.

when making such applications. The table shows some 17.74 Bcfd of liquefaction capacity under review at FERC, which is in addition to the 2.4 Bcfd of liquefaction capacity that was approved by FERC for the first four trains of Cheniere Energy's Sabine Pass project. Two of these projects, Jordan Cove and Oregon LNG, contemplate being supplied at least in part by western Canadian gas and have both received export licences from the NEB for this purpose.

In addition to the list of projects shown on Table 8 there are numerous other projects that have been announced that have yet to make any filings with FERC. In fact, the DOE reports it has received as many as 36 applications for export licences to Non-FTA countries with a total liquefaction capacity of 36 Bcfd.

Table 8: Proposed LNG Export Terminal Applications Currently Before FERC

Company (location)	**Quantity (a)**	Sponsor	FERC Status	Non FTA Export License Status
Sabine Pass Liquefaction, LLC (Sabine Pass LA)	1.4 (Bcf/d) (Trains 5 & 6)	Cheniere Energy	Approved	Pending
Freeport LNG Expansion, (Freeport TX)	1.4 Bcf/d	Freeport LNG Development	Approved	Approved
Lake Charles Exports, LLC (Lake Charles LA)	2.2 Bcf/d	Southern Union - Trunkline	Pending	Approved
Dominion Cove Point LNG, LP (Cove Point MD)	0.82 Bcf/d	Dominion	Approved	Approved
Jordan Cove Energy Project, (Coos Bay OR)	0.9 Bcf/d	Veresen Inc	Pending	Approved
Cameron LNG, LLC (Hackberry LA)	1.7 Bcf/d	Sempra	Approved	Approved
Corpus Christi LNG (Corpus Christi TX)	2.1 Bcf/d	Cheniere Energy	Approved	Approved
Oregon LNG (Astoria OR)	1.25 Bcf/d	Leucadia National Corporation	Pending	Approved
Excelerate Liquefaction (Lavaca Bay, TX)	1.38 Bcf/d	Excelerate Energy	Pending	Pending
Southern LNG Company, (Elba Island GA)	0.35 Bcf/d	Southern LNG	Pending	Pending
Magnolia LNG (Lake Charles LA)	1.07 Bcf/d	Liquefied Natural Gas Limited	Pending	Pending
CE FLNG, LLC (Plaquemines Parish LA)	1.07 Bcf/d	Cambridge Energy	Pending	Pending
Golden Pass (Sabine Pass TX)	2.1 Bcf/d	Exxon Mobil	Pending	Pending
Total	17.74 Bcfd			

Plans to export Alaskan-sourced natural gas as LNG have also been announced, although the timing of this project is likely further out into the future than those listed above. BP PLC, Exxon Mobil Corp, ConocoPhillips Co. and TransCanada Corp are backers of the Alaska Southcentral LNG project that would include construction of a 1,300-kilometer pipeline from Alaskan North Slope gas fields to southern waters, near Valdez or Anchorage, where a new terminal would load 3.5 Bcf/d of liquefied gas onto tankers destined for Asia. The price of the project ranges from $45 billion to $65 billion.

3.2.9 South America

South America has recently emerged as an important market for LNG with the potential for growth as the region seeks to become more economically developed, thereby increasing its energy requirements.

Brazil has three regasification terminals, one in Pecem that has a regasification capacity of 0.25 Bcf/d and one in Guanabara Bay that was only recently completed has a capacity of 0.5 Bcf/d. These plants are owned by Petrobras and the purpose of these projects is to provide fuel for power generation. In late 2013 a third LNG plant was commissioned. The Bahia terminal in the Bay of All Saints has a capacity of 0.5 Bcf/d. This terminal is also owned by Petrobras.

Argentina is also stepping up its ability to import LNG to sustain its rapid economic growth. It currently has one plant in operation called Bahia Blanca that has a capacity of 0.4 Bcf/d. Argentina will more than double its LNG import capacity once a second plant comes on stream in June. This plant, called Escobar, has a capacity of 0.5 Bcf/d. A proposal is in the works to build a third terminal in partnership with LNG exporter Qatargas that could allow even larger purchases of the fuel in about two years. This plant, known as Golfo San Matias, has a proposed capacity of 0.7 Bcf/d.

Chile has also recently added the ability to import LNG by constructing two import terminals, the Quintero facility and the Mejillones facility. Quintero has a regasification capacity of 0.35 Bcf/d while Mejillones has a regasification capacity of 0.2 Bcf/d.

4 Canada's LNG Export Opportunity

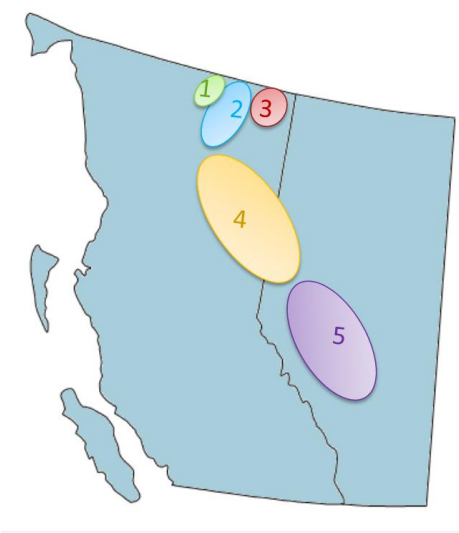
This section examines the reasons why Canadian producers want to participate in the LNG export market given Canada's large resource potential and growing unconventional gas production, proximity to Asian markets and the increasing level of competition Canadian producers face in the traditional North American markets they currently serve.

4.1 Impetus for Canada's Participation in World LNG Export Market

4.1.2 Large Resource Base Near Canada's West Coast

By any measure, Western Canada's natural gas resource base is very large. The National Energy Board estimates the ultimate potential for conventional marketable natural gas in the Western Canadian Sedimentary basin to be 291 Tcf.[3] To the end of 2014 cumulative production from Western Canada amounted to approximately 200 Tcf. Western Canada's unconventional gas resources, however, are vast and lie well beyond the future needs of Canadians. Figure 10 shows that unconventional gas reserves in five potential plays in Western Canada amount to nearly 700 Tcf, while Canada annually consumes only three Tcf. A large portion of these unconventional gas resources are found in the Horn River and Montney plays in northeastern B.C. The location of these resources is also shown in Figure 10 below.

Figure 10 - Western Canada Unconventional Resource Plays



	Play	Reserves (Tcf)	Source
1.	Liard	42[1]	BCOGC
2.	Horn River	78	NEB/BC MEM
3.	Cordova Embayment	40[2]	BCOGC
4.	Montney	449	NEB/BCOGC/ AER
5.	Duvernay	89[3]	AER
	Total	698	

Notes: [1] Based on 210 Tcf Potential Resource & 20% recovery rate; [2] Based on 200 Tcf Potential Resource & 20% recovery rate [3] Based on 443 Tcf GIP & 20% recovery rate

[3] "The Ultimate Potential for Unconventional Petroleum from the Montney Formation of British Columbia and Alberta", National Energy Board, BC Oil & Gas Commission, Alberta Energy Regulator, British Columbia Ministry of Natural Gas Development, November 2013, page 6

4.1.3 Infusion of Foreign Investment

The emergence of these unconventional gas plays in B.C. has generated worldwide interest and a number of joint ventures have been announced where Asian investments are being made in the development of these resources. In March 2010, Encana signed an agreement with Korea Gas Corp. that saw the Asian company buy a 50 per cent stake in properties in the Horn River Basin and Montney shale gas plays in B.C. In August 2010, Penn West Energy Trust entered a gas joint venture with Japan's Mitsubishi Corp to develop properties in the northeastern corner of B.C. Malaysia's national oil company Petronas is investing $1.07 billion to gain access to shale gas assets in northeastern B.C. In June 2011, Progress Energy Resources Corp. announced it has struck an agreement with Petronas to develop a portion of Progress' Montney shale assets in the foothills of northeastern B.C. Subsequent to announcing this joint venture, Progress and Petronas announced Petronas' Canadian subsidiary, and Progress entered into an agreement for the purchase by Petronas Canada of all of Progress' outstanding common shares in a the transaction valued at approximately $5.5 billion.

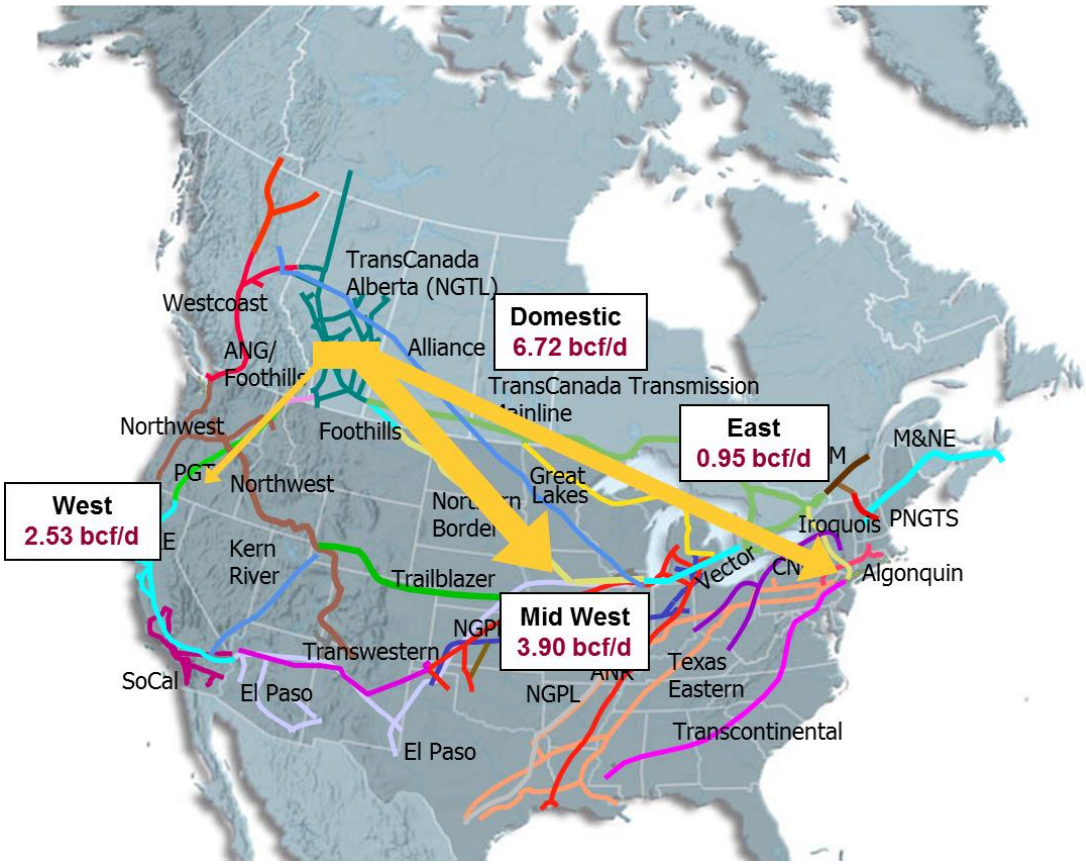
In February 2012, Encana entered into an agreement with Mitsubishi Corp that will see the Japanese company invest approximately $2.9 billion for a 40 per cent interest in the Cutbank Ridge Partnership. This Partnership holds about 409,000 net acres of Encana's undeveloped Montney-formation natural gas lands in the company's Cutbank Ridge resource play in northeast B.C. In the same month, PetroChina Co. signed binding agreements to buy a stake in a Royal Dutch Shell PLC shale-gas asset in Canada, specifically completing the acquisition of a 20 per cent stake in Shell's 100 per cent-owned land and assets in Groundbirch in northeastern B.C. It was reported that the acquisition could be worth slightly more than $1 billion. Meanwhile, with regards Alberta-based unconventional gas plays, in December 2012 Encana entered into a joint venture arrangement with Phoenix Duvernay Gas (Phoenix), a wholly owned subsidiary of PetroChina, to explore and develop Encana's extensive undeveloped Duvernay land holdings in west-central Alberta. Under the terms of the agreement, Phoenix will gain a non-controlling 49.9 per cent interest in Encana's approximately 445,000 acres in the Duvernay play for total consideration of $2.18 billion.

In March 7, 2014 Progress Energy and Petronas signed transaction agreements allowing Indian Oil Corporation Ltd. to acquire a 10 percent interest in Progress Energy's LNG-destined natural gas reserves in northeast B.C. and in the proposed PNW LNG export facility on Canada's West Coast. Later that same month, Talisman Energy Inc. announced the completion of the sale of approximately 127,000 net acres of its Montney position in northeast British Columbia to Progress Energy (a subsidiary of Petronas) for a total cash consideration of $1.5 billion.

4.1.4 The Need for Market Diversification

To date, western Canadian gas production only serves North American markets. Of the total 14.1 Bcf/d of gas produced in Western Canada in 2014, 6.72 Bcf/d was consumed in Canada, while the remaining 7.4 Bcf/d was exported to the United States. Traditionally, as shown in Figure 11 below, western Canadian gas has served markets in California, the Pacific Northwest, the U.S. Midwest, the U.S. Northeast and the western and central Canadian markets.

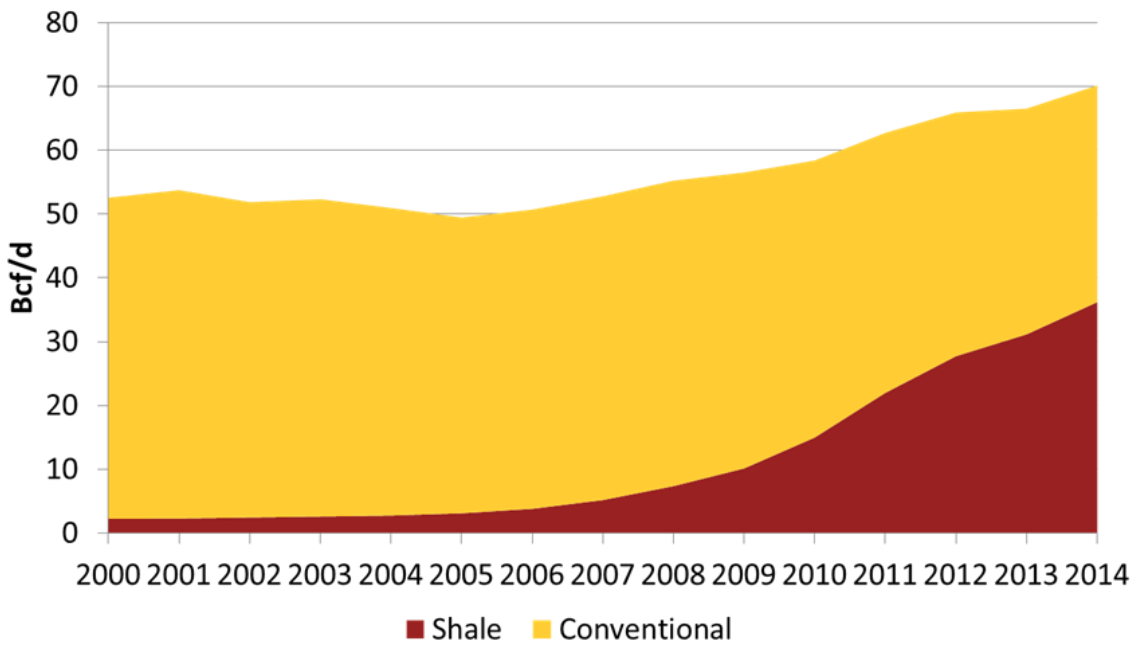
Figure 11 - Selected North American Gas Pipelines & Markets Traditionally Served by Western Canadian Gas



Just as technology unlocked the shale gas potential in Western Canada, it has similarly unlocked the same potential in a number of other shale basins elsewhere in North America. In addition, several of the plays that are under more active development, notably the prolific Marcellus basin, are located in the eastern half of the United States and are quite close to U.S. Northeast markets traditionally served by western Canadian gas. Figure 12 shows the marked increase in U.S. natural gas production in recent years driven by the emergence of shale gas production as a major source of supply which now

accounts for well over one-third of total U.S. supply. As production increases from these emerging U.S. shale plays, western Canadian production will face more competition for its traditional markets in the U.S. Midwest, U.S. Northeast and the central Canadian market. As more competition emerges for these traditional markets, it makes sense for western Canadian producers to explore new alternative outlets for their natural gas production.

Figure 12 – U.S. Dry Marketable Natural Gas Production



4.1.5 Proximity to the Rapidly Growing S.E. Asian Gas Markets

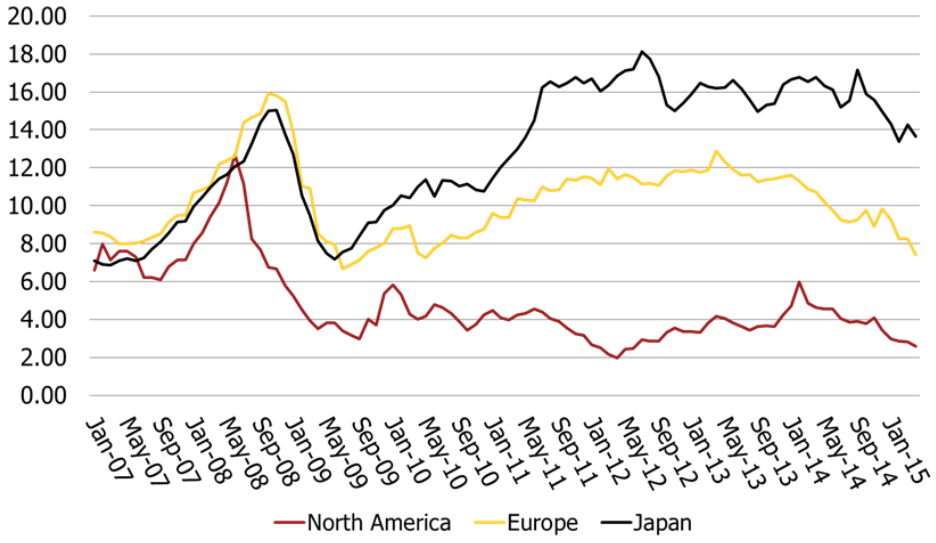
The Asian energy market is significantly closer to the West Coast of Canada than European markets. Thus it makes sense for western Canadian producers to examine market opportunities in this region. With only eight sailing days to Japan and 11 sailing days to China, the West Coast ports of Kitimat and Prince Rupert are closer than any other North American port to these markets.

4.1.6 Economic Drivers

As surging U.S. shale production became available to the market, gas-on-gas competition has resulted in North American gas prices becoming significantly lower than prices elsewhere in the world (see Figure 13). Also, even with oil prices falling from over US$100 per barrel to around US$60 per barrel at the time of writing, gas is still selling at

less than one-third of its energy equivalent basis to crude oil.[4] As many European and particularly Asian natural gas price contracts are more closely tied to oil prices (see Section 1), there exists the potential for western Canadian gas producers to obtain a higher netback for their production if they are able to access world markets while North American prices remain relatively depressed.

Figure 13 – Global Natural Gas Prices US$/MMbtu

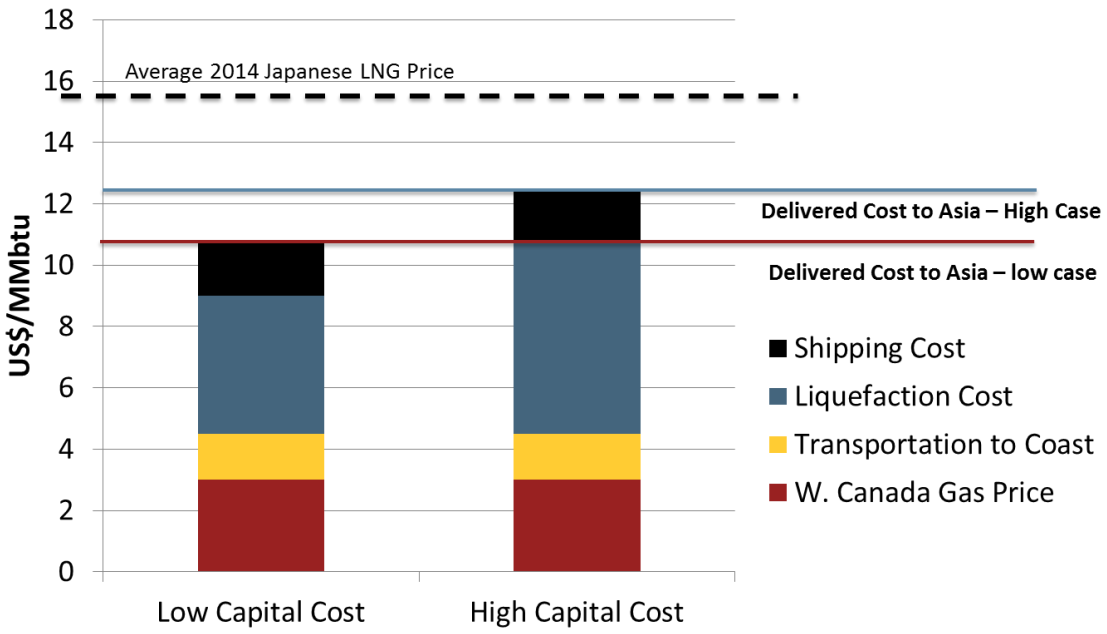


Source: World Bank

While a substantial price gap exists between North American natural gas prices and those in Asia, Canadian producers will incur significant additional costs to serve this market. The challenge for these producers will be to control the level of costs so that the landed costs of LNG from Canada are competitive in the Asian marketplace and to ensure producers receive a netback that renders these projects economic. Figure 14 below identifies the additional costs that would be incurred by a producer serving the Japanese market from an LNG export facility located on the West Coast. These incremental costs include pipeline transportation costs from the western Canadian market hubs to the coast, liquefaction costs and shipping costs to Asia via LNG tanker. The largest cost component is expected to be the cost of liquefaction so the ability to control these costs in particular will have a significant impact on the economics of such projects.

[4] One barrel of oil contains six times the energy of one thousand cubic feet of natural gas.

Figure 14 - Additional Costs of LNG Exports Expressed on a Per MMBtu Basis



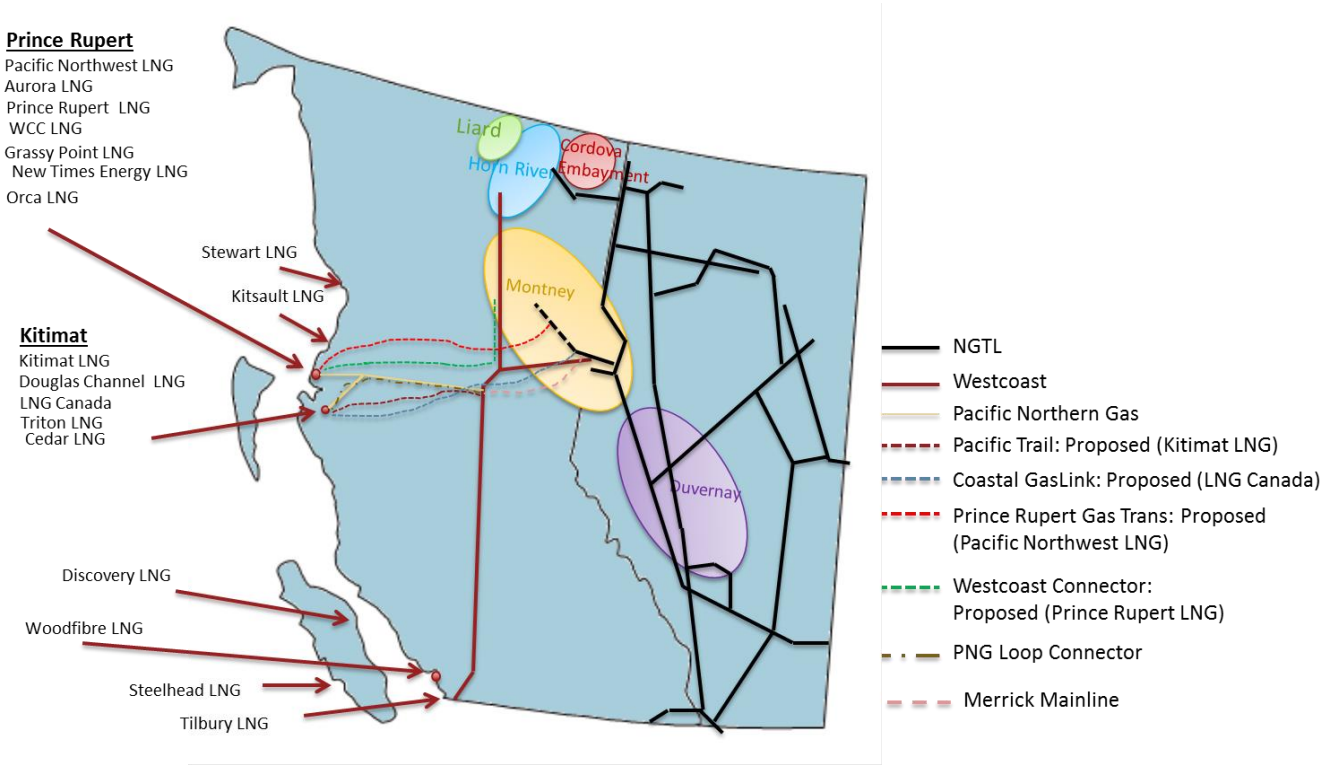
Notes: High cost involves Liquefaction capital cost of $1,500/t
Low cost involves Liquefaction capital cost of $1,000/t

While the average LNG price realized in Japan may decline from levels achieved in 2014, particularly if oil prices remain well below US$100 per barrel, there still appears to be an opportunity for LNG exports from Western Canada to be a competitive source of supply to this market

4.2 Potential Canadian West Coast LNG Export Terminals.

As a result of the factors described above that provide Canada with its LNG export opportunity, a large number of LNG export terminals have been proposed for Canada's West Coast that are in various stages of development. While none are yet under construction, a number of projects are far advanced in obtaining the necessary regulatory approvals that would be required for a project to proceed to construction. Figure 15 below identifies the projects that have been proposed and any affiliated pipeline project. A brief description of each project and its status follows.

Figure 15 – Proposed West Coast LNG Plants and Affiliated Pipeline Projects



Pacific Northwest LNG

Pacific Northwest LNG is majority owned by Petronas, the national oil and gas company of Malaysia. JAPEX, Sinopec/Huadian, Indian Oil and Petroleum Brunei are also partners in the project and the development of its associated natural gas supply. The proposal consists of an LNG export facility on Lelu Island in the District of Port Edward near Prince Rupert. Initially the project will include two trains, with the ability to expand with the addition of a third train. The output of LNG is expected to be six million tonnes per annum (0.8 Bcf/d) per train. In December 2013, Pacific Northwest LNG received its export licence for 2.74 Bcf/d from the NEB. In June 2015 Petronas announced a conditional final investment decision that indicated it planned to proceed with the project subject to two conditions: final approval from the Canadian Environmental Assessment Agency, and the B.C. legislature's ratification of a project development agreement between the province and Pacific Northwest LNG. TransCanada has been selected to design, build, own and operate the proposed $5 billion Prince Rupert Gas Transmission pipeline that will transport natural gas primarily from the north Montney gas-producing region near Fort St. John, B.C., to the Pacific Northwest LNG export facility.

Prince Rupert LNG

Prince Rupert LNG is owned by BG Group and has a proposal to build an LNG export facility on Ridley Island, B.C. The first phase of the project calls for two trains and will export 14 million tonnes per annum (1.8 Bcf/d equivalent) and phase two will bring an additional train of seven million tonnes per annum (0.9 Bcf/d). Prince Rupert LNG received an export licence for 2.91 Bcf/d from the NEB in December 2013. BG has announced a joint venture pipeline with Spectra Energy, known as the Westcoast Connector, that will extend 850 km. from northeast B.C. to Ridley Island near Prince Rupert. The pipeline will be capable of transporting up to 4.2 billion cubic feet per day of natural gas and will connect with the Spectra Energy system at its Station 2 facilities.

Aurora LNG

Aurora LNG is owned by Nexen Inc and INPEX CORPORATION of Japan and has plans to develop an LNG facility at Grassy Point, B.C. Aurora was awarded this location by the B.C. government after submitting an expression of interest along with a number of other parties. An export licence in the amount of 3.12 Bcf/d has been granted by the NEB.

WCC LNG

ExxonMobil and Imperial Oil have announced a partnership in WCC LNG. WCC LNG has selected Tuck Inlet near Prince Rupert as the site for its project. In December 2013 the project was granted an export licence from the NEB for 30 million tonnes per annum (four Bcf/d). No pipeline proposals associated with the project have yet been made public.

Grassy Point LNG

Woodside, an Australian company, is also pursuing an LNG export project in Western Canada. The company is the largest independent operator of oil and gas in Australia, where it has an extensive network of LNG operations. Woodside has reached an agreement with the B.C. government regarding the location for a new LNG export facility at the southern parcel of Grassy Point near Prince Rupert. Woodside is pursuing an LNG export project in the range of 10 to 15 million tonnes per annum, or 1.8 to 2.5 Bcf/d, including allowances for fuel gas. It was granted an export license in January 2015.

NewTimes Energy Ltd

NewTimes Energy Ltd proposes to develop an LNG facility near the Port of Prince Rupert. It has applied for an export licence with the NEB for the amount of 1.6 Bcf/d.

Orca LNG

Orca LNG is currently assessing building an LNG export facility in the Prince Rupert area. The project applied for to the NEB in September 2014 for an export licence to export 3.2 Bcf/d.

Kitsault LNG

The Kitsault Energy project is proposed to be constructed and operated near Kitsault, B.C. Kitsault Energy is a Canadian corporation registered in Ontario. In April 2014 Kitsault Energy applied for a licence with the NEB to export 2.7 Bcfd.

Stewart Energy LNG

Stewart Energy LNG is proposed to be constructed and operated near Stewart, B.C. Stewart Energy is a Canadian corporation registered in B.C., and at full capacity the Project will be capable of producing 30 MMt of LNG or 4.04 Bcf/d.

Kitimat LNG

Kitimat LNG is equally owned by Woodside Petroleum and Chevron Canada, with the latter being the operator. The project proposes an LNG terminal to be built at Bish Cove near the port of Kitimat, B.C. The project would be built in two phases, and after completion of the second phase it would have the capability of exporting some 1.4 Bcf/d of natural gas. The proponents applied to the National Energy Board for an export licence, which was granted in October 2011. The Kitimat LNG plant will be supported by the Pacific Trail Pipeline, which received environmental approval in 2008.

Douglas Channel LNG

AltaGas DCLNG Lease Limited Partnership holds a long-term lease agreement with the Haisla Nation on land locate eight kilometers west of Kitimat. Ultimately, the project proponent intends to develop a one Bcf/d export facility. The project would be developed in two phases consisting of floating liquefaction facilities with the capacity to receive 110 MMcf/d of gas. Partners involved in this first phase are AltaGas Idemitsu JVLP, EXMAR NV and EDF Trading Limited. The partners intend to make a final investment decision with respect to the project's first phase by the end of 2015 and to commence first deliveries of LNG in 2018. On June 1, 2015, the project applied for an export licence for a volume not to exceed one Bcf/d. Gas for the first phase of the LNG project would be transported via the existing Pacific Northern Gas Ltd. system.

LNG Canada

LNG Canada is a joint venture comprised of Shell Canada Ltd., Korea Gas Corporation (KOGAS), Mitsubishi Corporation and PetroChina Company Limited that is proposing to build and operate a LNG export terminal in Kitimat. The project will consist of the construction and operation of natural gas treatment facilities, LNG liquefaction and storage facilities, marine terminal facilities, an interconnecting cryogenic LNG transfer pipeline, and supporting facilities/infrastructure. It will initially consist of two LNG processing units, or trains, each with the capacity to produce six million tonnes per annum (mtpa) of LNG (equivalent to 0.85 Bcf/d of natural gas), with an option to expand the project. LNG Canada has selected TransCanada Corporation to design, build, own and operate Coastal GasLink — a 700-kilometre pipeline that will connect natural gas from northern B.C. and the Western Canadian Sedimentary Basin to the proposed export facility near Kitimat. LNG Canada has obtained an export licence from the National Energy Board authorizing the export of up to 24 million tonnes (3.2 Bcf/d) of LNG per year for 25 years. In June 2015, the Canadian Environmental Assessment Agency approved LNG Canada's Environmental Assessment and the B.C. Environmental Assessment Office has issued an Environmental Assessment Certificate for the project.

Triton LNG

In January 2013, Calgary-based AltaGas Ltd. and refiner Idemitsu Kosan Co, Ltd. of Tokyo announced they will form a 50-50 partnership to investigate exporting LNG and liquefied petroleum gas (mainly propane) to Asia. This project was named Triton. AltaGas owns the Pacific Northern Pipeline system that is currently in service and delivers natural gas to Prince Rupert and Kitimat. The pipeline would supply proposed export facilities that target exports of two million tonnes per year (0.27 Bcf/d) of LNG by 2017. The proponents applied for an export licence which was granted in April 2014.

Cedar LNG

Cedar LNG is an export development company owned by the Haisla Nation. With its traditional lands located near Kitimat, the LNG processing facilities are expected to be constructed, owned and operated by partnerships or joint ventures owned directly by the Haisla and one or more industry participants. The Haisla are currently in negotiations with prospective business partners and have applied for an export licence.

Woodfibre LNG

Woodfibre LNG is owned by Woodfibre Natural Gas which proposes to construct a smaller project in Squamish, B.C., for the export of 2.1 million tonnes per annum (0.27 Bcf/d). This project received an export licence in the amount of 0.27 Bcf/d from the NEB in December 2013. The project would be located at a pulp mill site that was closed in 2006, and as such comes ready with a deep water port and an electricity transmission line

connected to the BC Hydro grid. To provide service to the proposed Woodfibre LNG facility, FortisBC will need to construct a 52-km pipeline expansion beginning in north Coqitlam and ending at the Woodfibre site. This extension is known as the Eagle Mountain project.

Discovery LNG

Quicksilver Resources Canada Inc. has filed an export licence application with the NEB for a proposed LNG facility that would be located near Campbell River, B.C. The export licence seeks permission to export 2.7 Bcf/d. The contemplated project site was formerly occupied by the Elk Falls paper mill and as a result the project would be built on an existing industrial site.

Steelhead LNG

The Steelhead Group intends to develop LNG facilities to support a cumulative export capacity of 4.25 Bcfd of natural gas. The project would be located on Huu-ay-aht First Nations land at Sarita Bay at the southern end of Alberni Inlet on Vancouver Island. An export licence application has been filed with the NEB.

Tilbury LNG (Wespac Midstream)

WesPac Midstream is 85 per cent owned by Highstar Capital LP, a Delaware limited partnership; 7.5 per cent owned by Primoris Services Corporation, a publicly traded construction firm incorporated in Delaware; and 7.5 per cent owned by its management. WesPac Midstream proposes to export LNG produced at the Tilbury LNG plant in Delta, B.C. The Tilbury LNG plant is owned and operated by FortisBC Energy Inc. (FEI), and it has a production capacity of approximately five million cubic feet per day of natural gas equivalent LNG production. LNG is currently produced at the Tilbury LNG plant for sale in local and regional markets, and for utility peak shaving service to enhance local gas system reliability. The Tilbury LNG plant is currently being expanded to increase the LNG production capacity at the site by approximately 33 million cubic feet per day of natural gas equivalent LNG production. Pursuant to a development agreement with affiliates of FEI, Wespac is currently developing a marine terminal facility (the WesPac LNG Marine Terminal) on the Fraser River adjacent to the Tilbury LNG Plant. The WesPac LNG Marine Terminal will provide a means of loading LNG produced at the Tilbury LNG Plant onto LNG carrier ships for bulk transport and export from Canada. Wespac Midstream has applied to the NEB for an export licence for the amount of 0.4 Bcf/d.

4.3 Potential Eastern Canadian LNG Export Projects

GNL Quebec Inc. – Energie Saguenay Project

GNL Quebec Inc. is proposing to develop a LNG export facility at the Port of Grande-Anse in La Baie on the southern bank of the Saguenay River. The site offers a deep-water port which is open year-round. A new 650-km natural gas pipeline running from a point on the TransCanada Pipelines Limited Eastern Triangle infrastructure is expected to supply feed gas to the project. As such the project envisages being supplied by western Canadian gas. The project sponsors have applied for a licence to export 1.56 Bcf/d.

Stolt LNGaz

Stolt LNGaz is a joint venture formed by Stolt-Nielsen Gas Limited, SunLNG Holding Limited and LNGaz Inc. that intends to build and operate a medium-scale LNG production and distribution facility in Quebec. The project would be located in the Becancour Industrial Park on the St. Lawrence Seaway. At full build-out the facility is expected to include two trains producing a total of 0.14 Bcfd with about half of this production slated for export. The project proponents have applied to the NEB for an export licence.

Goldboro LNG

The Goldboro LNG Project developed by Pieridae Energy (Canada) Ltd. would be located at the Goldboro Industrial Park near Goldboro, N.S. The terminal will be comprised of a natural gas treatment/liquefaction plant, LNG storage, and marine and truck loading facilities. Pieridae has received its environmental assessment permit to construct the facility from the Nova Scotia Department of Environment. The proponents have applied to the NEB to import natural gas from the United States to Canada at the interconnect between Maritimes and Northeast Canada pipeline and the Maritimes and Northeast U.S. pipeline along the Canada-U.S. border between the New Brunswick and Maine. As such, U.S. gas production would be able to be used as feedstock for the plant in addition to any Canadian gas. The project has also applied for a licence to export 1.4 Bcf/d. In June 2013, Peiridae announced it had entered into a long-term sales agreement for five million tonnes per annum (0.7 Bcf./d) with E.ON Global Commodities SE to supply markets in western Europe.

Bear Head LNG

Bear Head LNG is a subsidiary of Liquefied Natural Gas Limited, an Australian publicly listed company based in Perth. The project proposes to export LNG from a facility on the existing Bear Head site in Richmond County near Point Tupper, N.S. This site was formerly intended as an import terminal. The proponent is seeking authority to import gas from the U.S. to supplement Canadian gas as a feedstock for this export facility. An export licence has been applied for to export 1.6 Bcf/d of LNG.

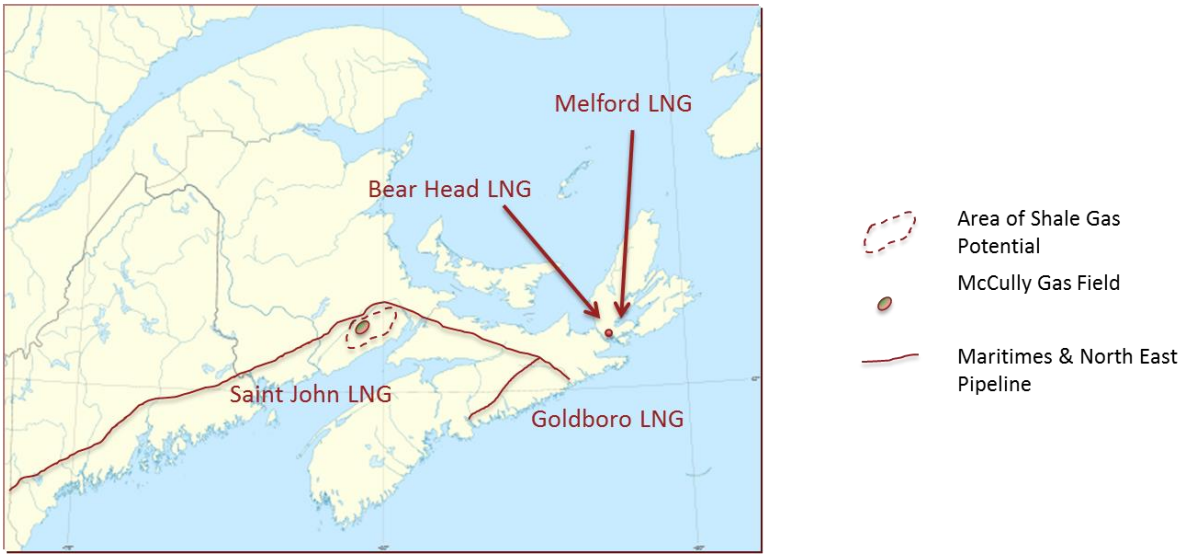
Melford LNG

Melford LNG is proposing to construct an LNG export facility at Myers Cove in Middle Melford, N.S. The project is being developed by H-Energy, a division of Mumbai-based Hiranandani Group. The project envisages receiving gas via the existing Maritimes and Northeast Pipeline and converting the natural gas into LNG for shipment to markets in Europe and Asia. The project proponents are applying for both import and export permits to allow it to use U.S. gas as well as Canadian gas as feedstock. The export licence is for exports of two Bcf/d.

Saint John LNG

Saint John LNG is, through various affiliates, being sponsored by Repsol, S.A. of Spain which plans constructing an LNG export facility at the site of the existing LNG regasification terminal at Canaport, N.B. The import terminal, also owned by Repsol, started operations in 2009 and currently operates with a maximum send-out capacity of 1.2 Bcf/d. Repsol is evaluating the prospect of sourcing feed gas supply from the United States and/or Western Canada. The gas would be transported to the proposed LNG Liquefaction Project via a Canadian transportation route and/or a U.S. transportation route. For both Appalachian and WCSB supply options, Repsol SJLNG is seeking to secure long-term transportation capacity. In the case of Canadian feed gas supply, gas would be procured from producers either on TransCanada's NGTL System (i.e. AECO) or at Empress. The gas would then be transported on TransCanada's Mainline Pipeline and Trans Quebec & Maritimes Pipeline to an interconnect with Portland Natural Gas Transmission (PNGTS) at East Hereford. At East Hereford, the gas would enter the United States and would be transported on PNGTS and Maritimes & Northeast Pipeline to Baileyville, Maine. At Baileyville, the gas would re-enter Canada (near St. Stephen, N.B.) and would be transported on the Emera Brunswick Pipeline to the LNG Liquefaction Project. Thus the proponent of the project is applying for both import and export permits to allow it to use U.S. gas as well as Canadian gas as feedstock for the project. Its export licence seeks authority to export 0.7 Bcf/d of liquefied natural gas.

Figure 16 – Proposed East Coast LNG Export Plants



4.4 Market Access & Canada's Natural Gas Production Potential

As noted earlier, Western Canada contains vast unconventional gas reserves, as do other areas of North America. As recently as 2007, 10.4 Bcf/d of western Canadian gas was exported to the U.S. However, this volume has declined to around 7.4 Bcf/d, and no recovery is anticipated due the emergence of large volumes of U.S. natural gas production from unconventional supply sources. While future declines in U.S. demand for western Canadian supply will be partly offset by the increase in oil sands natural gas demand and growing natural gas-fired power generation, to realize its full resource potential, Canadian producers will require access to new markets such as those that can be reached through the export of LNG.

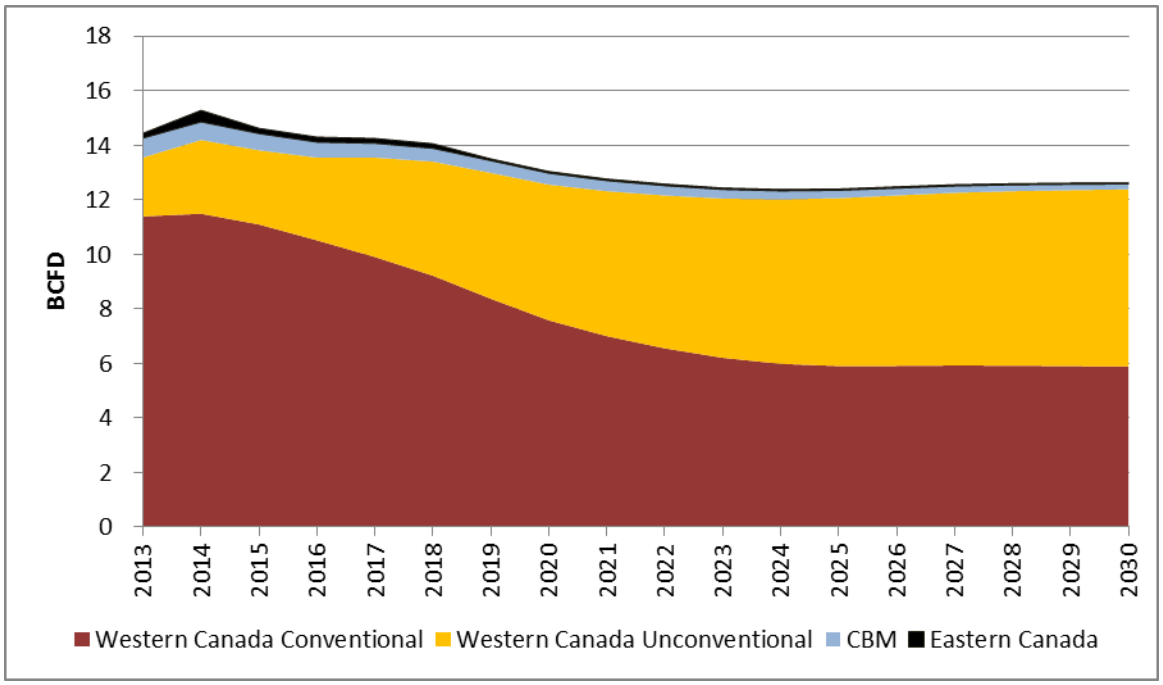
In preparing its most recent outlook of natural gas production, CAPP considered two market scenarios for Canada, namely (1) a market constrained case and (2) a new market opportunity case. The most significant difference between the two cases is that the latter assumes that by 2023, five LNG export trains will be in service on Canada's West Coast, with each train having the capacity to export five mtpa of LNG (or 0.7 Bcf/d per train). Case 1 by contrast assumes no LNG exports.

The ability to access new markets via LNG exports has a significant impact on the production outlook. In the market constrained case, western Canadian production continues to decline throughout the current decade and remains around 12 Bcf/d for the entire forecast period. In the new market opportunity case production begins to recover

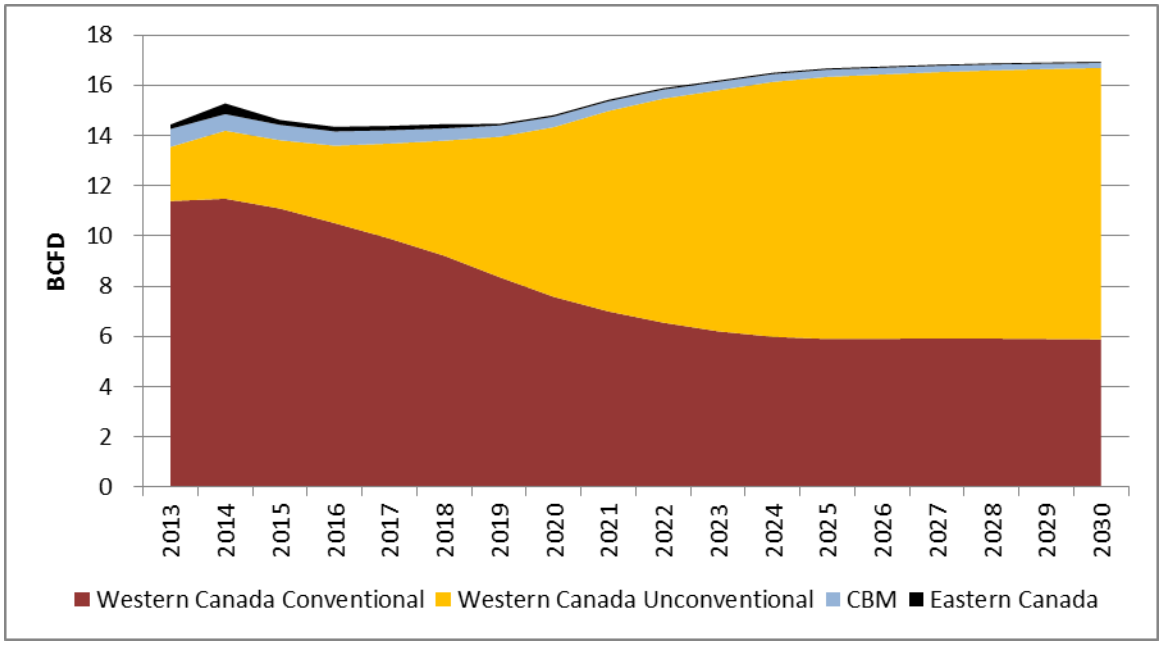
after 2018 when LNG export facilities start to come online and production rises to 17 Bcf/d by the end of the forecast period.

Figure 17 - Western Canadian Natural Gas Production

(a) Status Quo Case



(b) New Market Opportunity Case



4.5 First Nations

To date, First Nations have broadly supported the prospect of LNG exports from the West Coast. In the case of Kitimat LNG, for example, the liquefaction terminal is to be located on the traditional lands of the Haisla First Nation. A partnership agreement has been reached between Kitimat LNG and the Haisla that provides the First Nations group with the opportunity to purchase equity in the LNG project, minimum standards of employment during construction and operations, employment training, procurement opportunities, and, as part of the land-lease agreement between the federal government and Kitimat LNG, the Haisla will receive annual tax revenue and lease payments through Indian and Northern Affairs Canada.

In addition the B.C. government has announced a number of natural gas pipeline benefits agreements with First Nations that are part of the government's comprehensive approach to partnering with First Nations on LNG opportunities, which also includes development skills training and environmental stewardship projects with First Nations.

As recently as June 2015, two more First Nations, the Doig River First Nation and Halfway River First Nation, reached pipeline benefits agreements with the B.C. government. These nations are signatories to Treaty 8 in northern B.C. and have traditional territories that include the routes for TransCanada's proposed Prince Rupert Gas Transmission and Coastal GasLink natural gas pipeline projects. Doig River First Nation will receive approximately $1.29 million as Prince Rupert Gas Transmission project milestones are reached, while Halfway River First Nation will receive approximately $2 million as Prince Rupert Gas Transmission project milestones are reached. The province will also provide Doig River First Nation with approximately $1.35 million as Coastal GasLink project milestones are reached. Approximately, $2.4 million will also be provided to Halfway River First Nation as Coastal GasLink project milestones are reached.

In addition to construction-related milestone payments, the two First Nations will receive a share of $10 million a year in ongoing benefits per project. The ongoing benefits will be available to First Nations along the proposed natural gas pipeline routes. A more complete list of all pipeline benefits agreements signed between the B.C. government and First Nations are shown in Table 9 below.

Table 9 – Natural Gas Pipeline Benefits Agreements

First Nation	*The Pipeline to which the Benefit Agreement Pertains To*	*Date of Agreement*
Doig River	Coastal GasLink Pipeline Project	2015
Doig River	Prince Rupert Gas Transmission Project	2015
Gitxaala	Prince Rupert Gas Transmission Project	2014
Gitxaala	Westcoast Connector Gas Transmission Project	2014
Halfway River	Coastal GasLink Pipeline Project	2015
Halfway River	Prince Rupert Gas Transmission Project	2015
Kitselas	Coastal GasLink Pipeline Project; Prince Rupert Gas Transmission Project; Westcoast Connector Gas Transmission Project	2014
Lake Babine	Prince Rupert Gas Transmission Project	2015
Moricetown Band	Coastal GasLink Pipeline Project	2015
Nee-Tahi-Buhn	Coastal GasLink Pipeline Project	2014
Nisga'a Nation	Prince Rupert Gas Transmission Project	2014
Skin Tyee	Coastal GasLink Pipeline Project	2014
Wet'suwet'en	Coastal GasLink Pipeline Project	2014
Yekooche	Coastal GasLink Pipeline Project	2014
Yekooche	Prince Rupert Gas Transmission Project	2014

4.6 Conclusion

While competition for North American markets intensifies, it is highly likely that other producers, in addition to those that have already been announced, are seeking to develop joint ventures with overseas companies to develop their large unconventional gas holdings. These discussions may or may not involve associated LNG export facilities. However, the need for market diversification, particularly to markets that offer potentially higher netbacks, is a strong driving force for producers to explore these opportunities. Access to new markets will be required for Canada to realize its production potential.

As the worldwide use of natural gas increases, the size of the LNG market will grow as well. In fact, the EIA is anticipating the LNG market will account for a growing share of world natural gas trade as worldwide liquefaction capacity increases substantially. If this market grows as projected, Canada would still be a relatively small player overall, given the size of the LNG projects that have been announced to date in Canada. Based on this relatively small projected market share, Canada's entry into the world LNG market should not have any major market impacts in terms of price. Canadian producers would be price takers in the markets they wish to serve. Competition for a share of this growing market will be fierce, however, as other countries, notably Australia and the U.S., are also

seeking to develop large quantities of unconventional gas resources with a view to supplying the world LNG market. It is also worth noting that Asian consumers may be seeking a reliable source of gas supply as well as the opportunity to participate in upstream gas development and might look favourably on Canada as a reliable option to diversify their supply portfolios.