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Waiting for the Next Train?

An Assessment of the Emerging Canadian LNG Industry

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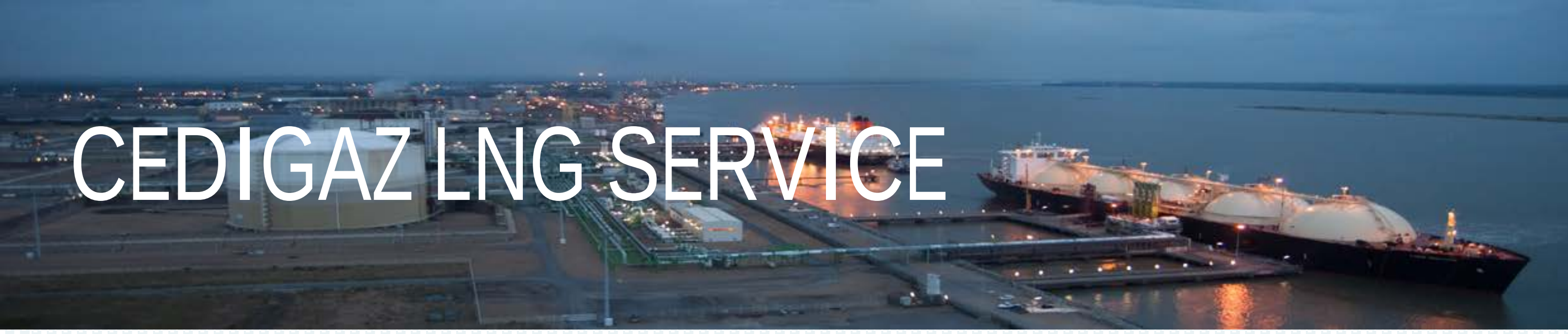

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Executive Summary

In February 2015, Canada counted 22 LNG liquefaction plant projects – of which 17 are located in British Columbia – representing a total design capacity of 325 mmtpa. Canada has the potential to become a major LNG exporter but no project has received Final Investment Decision (FID) so far. Competition with US brownfield projects with innovative business models have limited the commercial appeal of many Canadian projects relying on oil indexation. More recently, plummeting oil prices have put into question their profitability and lead to several postponements of FID reviews. This paper discusses the potential for Canada to export LNG, looking at the initial enthusiasm and wide support by public authorities and local communities but also at the economic challenges and commercial issues that are slowing the progress of these projects.

In 2013, Canada owned 2,028 Bcm of proved natural gas reserves and in 2012, remaining marketable gas resources were estimated to exceed 30,000 Bcm, located mainly in the Western Canada Sedimentary Basin. In 2013, natural gas consumption grew due to higher demand from the tar sands industry and reached 90 Bcm, while marketed production rebounded slightly to 145 Bcm after 10 years of continuous decline. Net exports to the United States, the only export market for Canadian gas, kept decreasing to 55 Bcm. In the future, consumption is expected to grow at a slower rate than production and net exports to the United States to keep declining. As a consequence, LNG appears to be an ideal solution to monetize gas and to unlock these large resources. However, CEDIGAZ does not expect material LNG exports to start before 2021, but they could reach 34 mmtpa by 2035.

Since the very beginning of the wave of LNG project proposals, Canadian federal and provincial authorities have appeared very supportive. At the provincial level, the government of British Columbia has multiplied initiatives to favor the emergence of a LNG industry, including by lowering its proposed LNG income tax act to enhance competitiveness and financial viability. On the federal side, applications to export LNG are granted by the National Energy Board without restrictions and the environmental assessment process was simplified in 2012. In addition, First Nations are cooperative overall and 8 of them (out of 20 impacted by LNG projects) have already signed revenue-sharing agreements with proponents.

However, the development of projects has been slowed by uncertainties regarding the economics of the projects and difficulties in signing sales agreements. For a typical BC LNG plant, the break-even Asian sale price has been estimated at $11.8/mmbtu by CEDIGAZ in the base case scenario, which corresponds to a JCC price of $81/bbl for oil-indexed contracts with a 14.5% oil slope. The low case break-even price is $8.6/mmbtu while the high case price is $16.1/mmbtu. Considering oil long term price trend, Canadian projects should be profitable but will probably remain less competitive than US-produced LNG indexed to the Henry Hub price.

Based on six objective criteria, CEDIGAZ has identified a group of four front-runner projects which, as of February 2015, stand the best chances to succeed: Pacific NorthWest LNG, Goldboro LNG, LNG Canada and Douglas Channel LNG. The second group is composed of seven projects, dubbed challengers which are less advanced, but still have some chances to succeed. The third and last group contains the projects with the least chance of success as things currently stand.

Introduction

Over the past few years, Canada has been presented as a potential major LNG exporter. The fifth largest natural gas producer in the world is facing a moderate growth in domestic demand and declining net exports to the United States, making LNG the unique way to monetize its huge resources, estimated at 30,000 Bcm. After the massive arrival of Australian LNG on the market between 2014 and 2016, followed by that of US project starting with Cheniere's Sabine Pass in 2016, Canada could be one of the next big LNG producers. Attracted by this large potential, investors have multiplied LNG plants proposals and in February 2015, Canada counted 22 projects which represented a total design capacity of 325 mmtpa.

These projects are now at different stages of advancement and there is no denying that only a few of them will eventually succeed. However, following the enthusiasm of Canadian authorities attracted by potential economic windfalls and projects' proponents attracted by high Asian LNG prices, doubts have recently been raised about the economics of many Canadian projects especially under the prevailing market conditions. 2014 was thought to see the launch of the LNG industry in Canada, with major projects expected to reach FID, but it turned out to be the year of growing uncertainties. Despite some major progresses, including the vote of the LNG income tax act in British Columbia, first-class projects were delayed, sometimes without defining a new schedule. Most of them are greenfield and situated on the West coast of Canada, hundreds of kilometers away from the Western Canada Sedimentary Basin's (WSCB) production and represent very large investments. With declining international energy prices, including LNG prices, projects' economics are a key issue, together with the ability for proponents to find off-takers for their production.

In 2015, four Final Investment Decisions are expected for the Pacific NorthWest LNG, Douglas Channel LNG, Goldboro LNG and Woodfibre LNG projects. Among them, only one is a large-scale plant in British Columbia but positive decisions would launch the LNG industry in Canada.

The first section of this report looks back at the original enthusiasm for Canadian LNG exports and tackles the fundamentals of Canadian natural gas markets, including reserves and resources, imports and exports and supply and demand trends. The second section details the various supports to the development of a LNG industry in Canada, from public authorities to local communities. The third section addresses the uncertainties which surround the projects, especially the economic and commercial matters. The fourth section provides a project by project analysis and ranks them into three categories according to their chance to succeed, as of February 2015.

1. Liquefying Natural Gas: the way out for Canadian resources

Besides holding sizable proven gas reserves, Canada is endowed with huge unconventional resources. But with a limited domestic demand growth potential and dwindling net exports to the United-States, LNG appears to be the only way for Canada to monetize its potentially large gas surplus.

1.1 Natural gas resources in Canada

With an estimated 2,028 Bcm[1] of proven remaining gas reserves, Canada was ranked 20th worldwide according to Cedigaz. By way of comparison, the United States are credited with about 9,170 Bcm, the fifth largest reserves in the world. Geographically speaking, 93% of these reserves are located in the Western Canada Sedimentary Basin (WCSB), mainly in British Columbia and Alberta.

Besides these reserves, Canada can count on undeveloped but promising resources. In a 2013 report[2], the National Energy Board (NEB), the Canadian energy regulatory agency, has estimated remaining marketable resources to exceed 30,963 Bcm, including 24,390 Bcm (80%) in the WCSB. The latter stretches over British Columbia, Alberta, Saskatchewan, Manitoba and benefits from large unconventional resources. These are mainly located in the Montney Formation (12,700 Bcm in British Columbia and Alberta) and in the Horn River Basin (2,200 Bcm in British Columbia).

Table 1: Canadian Natural Gas Resources

		Remaining Established Reserves (year-end 2013)	Remaining Marketable Gas (year-end 2012)
WCSB	**British Columbia**	924	
	Alberta	916	24390
	Saskatchewan	54	
Ontario & Quebec		7	227
East Coast	**New Brunswick**	3	2578
	Nova Scotia	6	
Northern Canada	**Newfoundland,**	106	
	Mainland NWT		3286
	& Yukon	13	
West Coast	**British Columbia**		482
Total Canada		**2028**	**30 963**

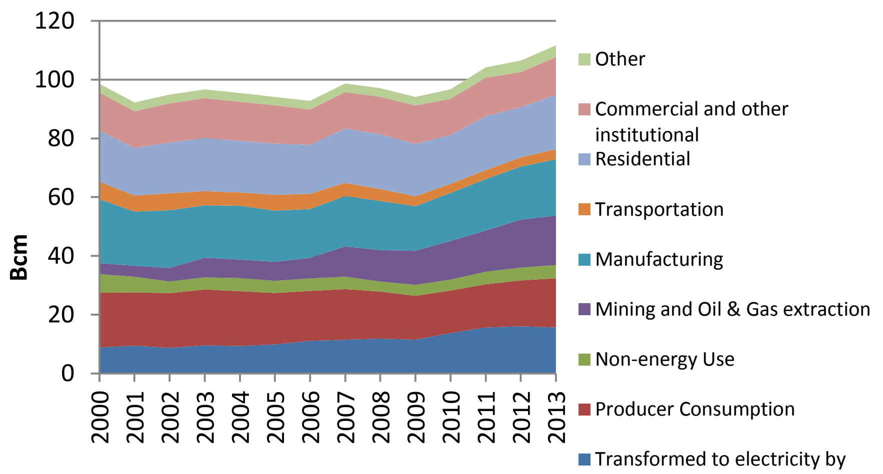
Source: NEB

[1] Source: CEDIGAZ Statistical Database. Reserves at December 31, 2013.
[2] NEB. *Canada's Energy Future 2013: Energy Supply and Demand Projections to 2035*. NEB, November 2013.

1.2 Consumption and supply of natural gas in Canada

During the first decade of the 21st century, domestic consumption was almost flat overall from 78 Bcm in 2000 to 82 Bcm in 2010[3]. Consumption started to grow again from 2011 as the economy was getting back on track after the 2009 recession and as the demand from the tar sands production was increasing. In order to recover the large but deeper bitumen deposits (the shallow deposits can be mined), producers use steam assisted gravity drainage technologies, which require lots of energy to heat water. As a consequence, natural gas demand from extractive industries in Canada rose from 3.8 Bcm in 2000 to 16.8 Bcm in 2013 and represented 19% of the Canadian consumption which peaked at 90 Bcm.

Figure 1: Canadian natural gas consumption by sector



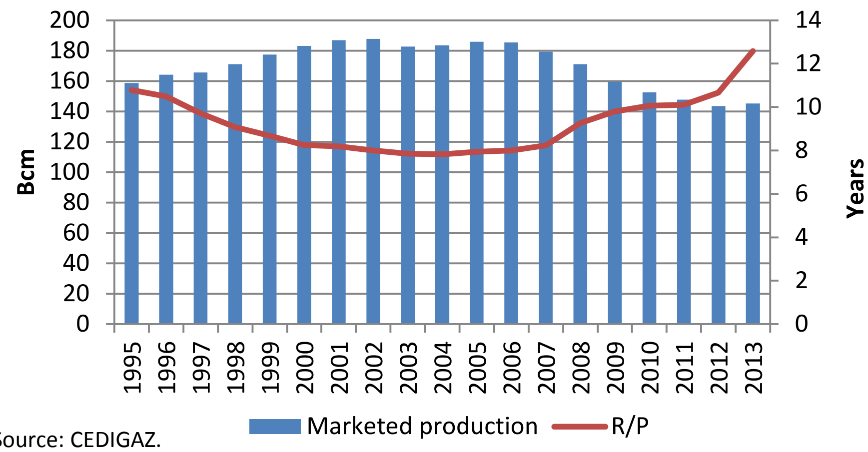
Source: Statistics Canada

On the supply side, Canada is the fifth largest producer in the world. Marketed production peaked in 2002 at 188 Bcm[4] and then declined to 144 Bcm in 2012. However, in 2013, as consumption grew by 5.2%, production rebounded slightly and Canada marketed 145 Bcm of domestically produced natural gas. This amount remains far from the 687 Bcm produced by the United States the same year, but it still enables Canada to be a net exporter.

[3] Source: Statistics Canada, CANSIM, Table 128-0016, *Supply and Demand of Primary and Secondary Energy in Terajoules.* Accessed on February 12, 2015. Data exclude producers' consumption. http://www5.statcan.gc.ca/cansim/a26?lang=eng&id=1280016

[4] CEDIGAZ Statistical Database

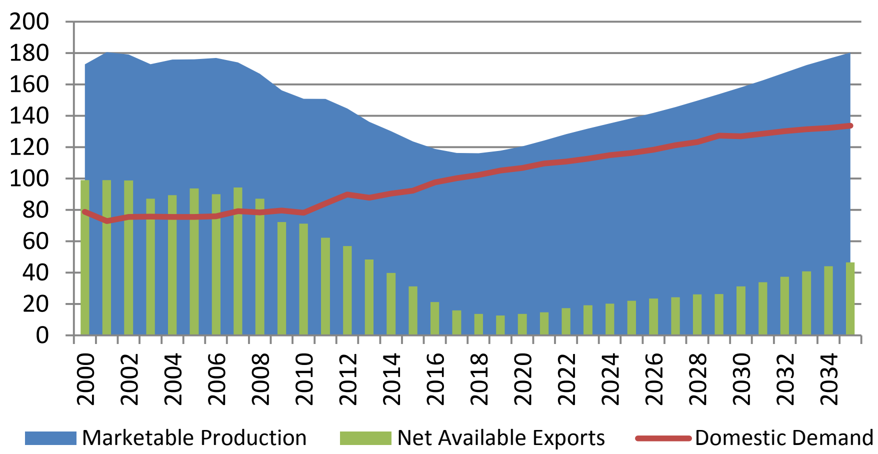
Figure 2: Canadian marketed production and reserves to production (R/P) ratio



Source: CEDIGAZ.
Note: R/P computed as the Reserves /(Gross production - Reinjection)

According to 2013 NEB's forecasts[5], Canadian domestic demand should, on average, grow at a lower rate than production between 2015 and 2035. Domestic demand is expected to grow at an average rate of 3%/year between 2015 and 2020 and then by 1.5%/year to 2035, reaching 107 Bcm in 2020 and 134 Bcm in 2035, while production is expected to decrease until 2019 before growing at a 2.7% average annual rate between 2020 and 2035. Marketed production would reach 121 Bcm in 2020 and 180 Bcm in 2035. Despite this decrease in the short-run, production will stay above domestic demand at any time. By 2035, according to NEB's base case price assumptions, Canada could have an excess of 47 Bcm/year of natural gas available for exports.

Figure 3: Canadian natural gas demand, production and exports forecasts



Source: NEB. Canada's Energy Future 2013

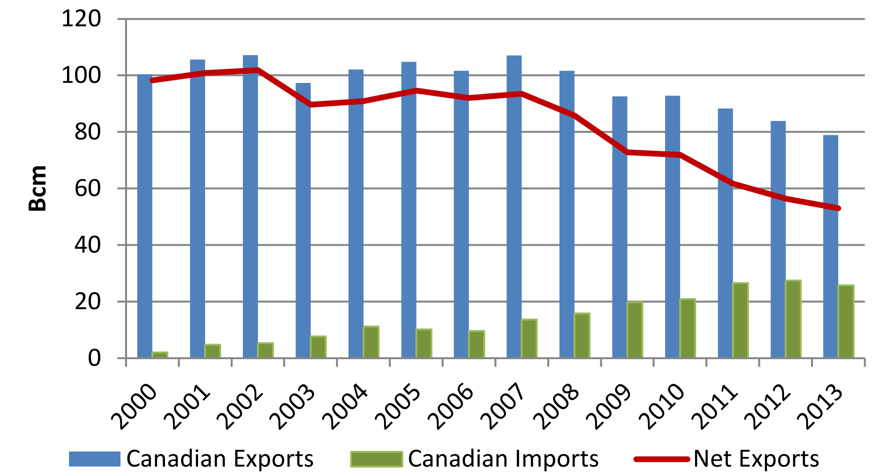
[5] NEB. *Canada's Energy Future 2013: Energy Supply and Demand Projections to 2035*. NEB, November 2013. Reference case scenario: WTI at $110/bbl and Henry Hub at $6.2/mmbtu in 2035.

1.3 Decreasing natural exports to the United States

Traditionally, the United States have been the only export market for Canadian natural gas. Both countries are connected by a large network of pipelines, which includes 33 connection points. The North American market is well integrated and trade flows are conducted in both directions.

Canada has always been a net exporter, but net exports have been declining sharply, from 95 Bcm in 2005 to 55 Bcm in 2013[6]. Over the period, exports decreased by 3.5%/year on average while imports increased by an average 12.4%/year rate because of the influx of Marcellus shale gas in the Ontario market. These new trade patterns reflect the continuous rise of the US shale gas production and one can expect Canadian net exports to the United States to continue their downward trend. In its 2014 *International Energy Outlook*[7], the US Energy Information Agency (EIA) forecasts a continuous decrease of net imports from Canada, down to 31 Bcm in 2020 and 12 Bcm in 2035.

Figure 4: US-Canada natural gas trade



Source: EIA

In this context, LNG exports appear to be an ideal solution for Canada to unlock its huge production potential. In its 2013 *Canada' Energy Future,* the NEB assumed[8] that the country would start exporting 7.5 million tons/year of LNG in 2019 from British Columbia, growing gradually to 23 million tons/year by 2023. As the NEB recognizes in its report, the actual exported volume could vary depending on North American natural gas prices, competition from other LNG supply basins, the pace of LNG demand growth, and the ability of Canadian LNG proponents to secure contracts with buyers. In fact, since the report's publication, projects have been delayed and CEDIGAZ does not expect any export before 2021. Considering the global LNG demand and the long-term patterns of natural gas markets in the world, CEDIGAZ estimates that Canada could export 34 mmtpa of LNG in 2035[9].

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[6] EIA Statistics. http://www.eia.gov/naturalgas/data.cfm

[7] EIA. *International Energy Outlook 2014*. EIA, September 2014. Reference Case Price Scenario: WTI is at $130/bbl in 2035 and $141/bbl in 2040 and Henry Hub at $7.7/mmbtu in 2040 (2012 dollars)

[8] NEB. *Canada's Energy Future 2013: Energy Supply and Demand Projections to 2035*. NEB, November 2013.

[9] CEDIGAZ, *Medium and Long-Term Natural Gas Outlook*. February 2015.

2. A Large Support of Stakeholders

With such a potential for LNG, projects' announcements have been thriving in the past few years, mostly in British Columbia. International Oil Companies as well as inexperienced LNG players have come up with proposals, receiving an almost unanimous support of federal authorities, provincial governments, and indigenous First Nations.

2.1 Federal authorities

On the Federal side, public authorities and agencies are showing their support to the development of the LNG industry in Canada. While ongoing operations of LNG terminals are generally regulated by provincial law, most of the proposals to build a new facility require both federal and provincial environmental assessments and permits. However, since *The Canadian Environmental Assessment Act* passed in 2012, a so-called "substitution tool" enables the Canadian Environmental Assessment Agency (CEAA) to transfer the reviewing/approval process to the provincial authority in charge of environmental assessments. This means that LNG projects can be reviewed by a unique agency instead of going through both provincial and federal processes, even though the CEAA still has to validate the provincial authority evaluation. In British Columbia, assessments are conducted by the B.C. Environmental Assessment Office (BCEAO). The latter in also in charge of assessing intra-provincial pipelines projects in British Columbia as they fall under provincial regulation. So far, four pipelines projects have received a certificate by the BCEAO but only two liquefaction projects have been authorized: Kitimat LNG (by the BCEAO) and Goldboro LNG (by the Nova Scotia Environment Department). Both projects' locations were initially intended to receive import terminals and could benefit from the permits granted to those import projects. In addition, only a very few numbers of projects have initiated the application process, and only two projects are currently under review: Pacific Northwest LNG by the federal agency and LNG Canada by the BCEAO. As for the 0.55 mmtpa Douglas Channel LNG, it falls under the threshold for an environmental assessment due to the size of stored hydrocarbons.

Table 2: Environmental Assessments of Canadian LNG Projects as of March 2015

Project	Province	Initial Capacity (mmtpa)	Additional Capacity (mmtpa)	CEAA' Status	Provincial Agency's Status
Goldboro LNG	N.S.	10		N/A	Approved
Kitimat LNG	B.C.	11		Approved	Approved
Pacific NorthWest LNG	B.C.	12	6	EA in Progress	Approved
LNG Canada	B.C.	13	13	Substitution	Under review
Woodfibre LNG	B.C.	2.1		Substitution	Under review
Prince Rupert LNG	B.C.	24	7	EA in Progress	Pre-Application
Aurora LNG	B.C.	12	12	Substitution	Pre-Application
Grassy Point LNG	B.C.	6 to 15	up to 20	Substitution	Pre-Application
WCC LNG	B.C.	15	15	Substitution	Pre-Application
Douglas Channel LNG	B.C.	0.55		EA not required	EA not required

Source: CEDIGAZ LNG Databases

Note: In British Columbia, Environmental Assessment is conducted by the BC Environmental Assessment Office. In Nova Scotia, they are conducted by the NS Environmental Office.

The second major authorization needed for proponents to move forward is the license to export LNG. In 2012, the *Jobs, Growth and Long-term Prosperity Act* exempted of hearings the National Energy Board to ease the export license application review. Since the first application filed by the Kitimat LNG venture in December 2010, 32 applications have been received and 13 have been approved. According to the NEB Act, while reviewing applications, “*the Board shall satisfy itself that the quantity of oil or gas to be exported does not exceed the surplus remaining after due allowance has been made for the reasonably foreseeable requirements for use in Canada, having regard to the trends in the discovery of oil or gas in Canada*.” Taking into account the fact that not all projects will succeed, the NEB evaluates each application on its own merit and this explains why the total quantity authorized to date (154 mmtpa) far exceeds the forecasted available surplus. On average, it takes 6 months to deliver the license and none has been denied so far, but some applications, such as Stewart LNG’s could not be reviewed because of incompleteness.

Table 3: NEB's Export Licenses as of March 2015

Project	Status	Export Volume (mmtpa)	Duration	Application Date	Decision Date
Kitimat LNG	Approved	10	20	09/12/2010	13/10/2011
LNG Canada	Approved	24	25	27/07/2012	04/02/2013
Prince Rupert LNG	Approved	21.6	25	17/06/2013	16/12/2013
Pacific NorthWest LNG	Approved	19.7	25	05/07/2013	16/12/2013
WCC LNG	Approved	30	25	22/07/2013	16/12/2013
Woodfibre LNG	Approved	2.1	25	23/07/2013	16/12/2013
Triton FLNG	Approved	2.3	25	29/10/2013	16/04/2014
Aurora LNG	Approved	24	25	29/11/2013	01/05/2014
Grassy Point LNG	Approved	20	25	18/07/2014	29/01/2015
Kitsault Energy	Under review	20	25	07/04/2014	
Steelhead LNG	Under review	30	25	08/07/2014	
Discovery LNG	Under review	20	25	29/07/2014	
Haisla Cedar 1 LNG	Under review	2.9	25	28/08/2014	
Haisla Cedar 2 LNG	Under review	5.8	25	28/08/2014	
Haisla Cedar 3 LNG	Under review	5.8	25	28/08/2014	
Orca LNG	Under review	24	25	04/09/2014	
Goldboro LNG	Under review	10	20	24/10/2014	
GNL Quebec	Under review	11	25	27/10/2014	
Bear Head LNG	Under review	12	25	07/11/2014	
Canaport LNG	Under review	5		12/02/2015	
Stewart Energy	Incomplete	30	25	05/03/2014	18/03/2014
Douglas Channel LNG	To re-apply				
H-Energy LNG	No application				

Source: CEDIGAZ LNG Databases

In addition to the overall support of federal agencies, politicians are also taking decisions to make sure the LNG industry have the best chance to see the light of the day. Thus, in February 2015, Canadian federal government granted tax breaks for the LNG sector to help proponents make their final investment decision. The Prime Minister announced that companies will be able to deduct a higher share of capital cost to compute net income thanks to a raise from 8% to 30% in capital cost allowance rate for LNG equipment acquired within the next 10 years. The rate for buildings is also raised from 6% to 10%.[10]

2.2 Provincial governments: the case of British Columbia

Attracted by the economic potential of developing a LNG industry in the western Province, the government of British Columbia has launched in 2012 the "BC LNG Strategy". Three years ago, the government was expecting three plants to be operating in 2020, providing $1 billion of additional revenue every year, creating 9,000 construction jobs and 800 long-term jobs. At the time, political leaders may have been too optimistic on the schedule, but it should be emphasized that although no project has been sanctioned yet, some companies have already invested heavily. Companies haven't released the total amount of spending, but it represents several billions dollars: for example, Petronas has already spent about $13 billion in acquiring Progress Energy, Talisman's shale assets and in developing prospective Montney holdings in northeast British Columbia. Since 2012, the government has kept being very supportive and has multiplied initiatives to favor the development of the LNG industry in British Columbia.

Well aware of the fact that projects would not take off without foreign investors - who may also be the ones to buy the Canadian output – British Columbia used diplomacy to promote industrial cooperation. In July 2014 for example, the Minister of Natural Gas Development of British Columbia Rich Coleman and the Administrator of the National Energy Administration of China Wu Xingxiong signed a Memorandum of Understanding to strengthen energy trade and investment[11]. Earlier in 2014, the Minister of Jobs also assured that the government was committed to deliver a trained workforce for jobs in the LNG Industry, as British Columbia and the Federal Canadian government have renewed the Foreign Qualifications Recognition funding agreement. These $3.3 million over three year will help improving the process for recognizing foreign qualifications of immigrants[12].

The most illustrative support of the British Columbian government was shown last year, when it proposed a new fiscal framework for the LNG sector. The draft presentation, introduced in the first place in February 2014 planned a tier-1 tax on operating income and a tier-2 tax on net income, with a rate up to 7%. The tier-1 tax could be deducted from the second one. However, sponsors' warnings on threats that such rates were representing for the economics of their projects prompted the government to review its plan. In the latest version, introduced in October 2014, the bill included the tier-1 1.5% tax on operating income, but the rate of the tier-2 tax was reduced to 3.5% for taxation years beginning on or after January 1, 2017 and to 5% for taxation years beginning on or after January 1, 2037[13]. The Minister of Finance, Mr. De Jong, said[14] that the

[10] Jang, Brent, and Ian Bailey. "Ottawa Grants Tax Breaks for LNG Sector in B.C.," February 19, 2015. http://www.theglobeandmail.com/news/british-columbia/harper-announces-tax-breaks-for-lng-industry-in-bc-to-spur-job-growth/article23106853/.
[11] "British Columbia, China Strengthen Ties to Natural Gas Future," July 24, 2014. http://www.newsroom.gov.bc.ca/2014/07/british-columbia-china-strengthen-ties-to-natural-gas-future.html.
[12] "$3.3M Investment Helps Integrate Skilled Newcomers into B.C.'s Workforce," August 6, 2014. http://www2.news.gov.bc.ca/news_releases_2013-2017/2014JTST0064-001123.htm.
[13] De Jong, Michael. *Liquefied Natural Gas Income Tax Act*, 2014. http://www.leg.bc.ca/40th3rd/3rd_read/gov06-3.htm.
[14] The Canadian News Press. "B.C.'s Two-Tiered LNG Tax Drops to 3.5%." *The Province,* October 24, 2014. http://www.theprovince.com/news/tiered+drops/10311866/story.html.

government took into consideration the increasing construction costs and the changing world market conditions, including the massive deal between China and Russia to import natural gas by pipeline. In addition, the bill also includes a corporate income-tax credit available to LNG companies that establish permanent bases in British Columbia. According to government's calculations, a 12 mmtpa liquefaction plant would pay under the new regime US$ 100 million a year for the LNG income tax and another US$ 560 million a year in royalties, carbon tax and other taxes. By responding to industry's claims, the British Columbian government showed that it was aware of the risk for the Province of missing the train if it did not keep attractive conditions for investors.

2.3 First Nations, an essential partner

Last but not least, Canadian LNG projects must ensure the support of First Nations, who usually own the land where companies intend to develop plants. Home to 198 Aboriginal groups, British Columbia hosts a third of Canadian First Nations. These groups are mainly located along the Fraser River and on the Vancouver Islands so that only about 20 of them are affected by the LNG plants or pipelines projects. Receiving the support of First Nations is considered as a key element for projects to succeed since they claim vast territories and their rights have been backed by many court victories. Since projects have started to flourish all along the coastline, First Nations have appeared to be supportive overall. Projects' sponsors have been very keen on working with local communities and showing the benefits of their projects. The Haisla Nation, whose traditional territory is situated along the Douglas Channel of Kitimat, is one of the most impacted but also one of the most involved. In August 2014, it has filed an export license application to the NEB for the CEDAR LNG Liquefaction barges project with a 5 to 15 mmtpa capacity. As the local newspaper the Vancouver Sun reported in January 2015[15], the support is mounting: at the time, 8 groups had signed revenue-sharing agreements with the British Columbian government or benefit agreements with projects' sponsors. The fly in the ointment is the outright opposition which has emerged in fall 2014 against the Pacific Northwest LNG project when a group of First Nations contested the location of the project on Lelu Island which may harm juvenile salmons. The Petronas-led consortium submitted an addendum to the Environmental Impact Statement in October 2014 proposing design changes to reduce the potential environmental damages, including redesigning the marine terminal and relocating the berths. The new proposal is now under review and since then, further Impact Benefit Agreement Term Sheets have been signed by the joint venture with several First Nations.

[15] Hoekstra, Gordon. "More First Nations Signing on in Support of LNG Projects in Northern B.C." *The Vancouver Sun*, January 7, 2015.
http://www.vancouversun.com/business/energy/More+First+Nations+signing+support+projects+northern/10709543/story.html?__lsa=635e-4189.

3. Assessing the economic viability of Canadian LNG projects

Since LNG projects were introduced for the first time, mostly between 2010 and 2012, proponents have started to delay Final Investment Decisions (FID). At first, companies were waiting for the local legislative framework to be set and to obtain the various required permits. More recently, as global energy prices, including LNG prices, started declining, proponents said they had to conduct further studies on the economic viability of their projects.

3.1 Capital-intensive projects

A liquefaction plant is costly in terms of capital investment and, as all complex projects, can be faced with unforeseen rises in expenditures. It requires expensive equipment and qualified workers. One of the Canadian features is that most of the projects are proposed on BC greenfield and environmentally sensitive sites, far from undeveloped WCSB reserves. Unlike the neighboring US projects, proponents have to support an integrated cost including the liquefaction plant and upstream development, while the pipeline construction and operation is left to a third-party.

LNG liquefaction terminal

Highlighting the large uncertainties surrounding the cost of liquefaction plants in Canada, proponents provide a range for capital expenditures estimates rather than a reference case amount, except for Pacific NorthWest LNG which evaluates capital expenditures for the first phase (12.8 mmtpa) at $11 billion. Shell's LNG Canada gives an estimate of $23 to $36 billion for 26 mmtpa, that is to say $900/tpa to $1,400/tpa. ExxonMobil, which is still conducting feasibility studies, provides an even larger range, from $1,000/tpa to $2,000/tpa. In fact, such uncertainties are mostly due to the risk of costs inflation which can occur in case of labor and/or material shortage, as the Australian example recently proved. By way of comparison, the greenfield Corpus Christi plant proposed by Cheniere in the United States is estimated at $14.5 billion for a 13.5 mmtpa design capacity, i.e. $1,100/tpa. This amount is much higher than the one expected for brownfield projects (700/tpa for Sabine Pass for example) which benefit from existing equipment like storage tanks or marine berths, but it is also the most relevant standard.

Upstream development

In addition to the plant, sponsors who chose an integrated development structure will have to sanction large upstream development costs. To secure feed gas from the WCSB, proponents have first started to acquire acreages and well established companies: in 2012 for example, Petronas acquired Progress Energy for about $5.2 billion to hold the largest acreage in shale gas in the North Montney area and in 2013, the Malaysian company was owning 5.2 billion boe of unconventional resources (2C + 2P). To develop these large resources, Petronas plans to invest $10 billion which has to be added to the liquefaction plant cost. Similarly, Kitimat LNG, which owns about 15 Tcf of resources in the Horn and Liard Basin will have to invest massively to develop its resources.

Pipelines from WCSB to the coast

Due to the location of resources, projects' proponents have developed pipelines projects and four of them have already been granted an environmental permit. However, LNG joint-ventures are not expected to own this infrastructure. TransCanada, the second largest pipeline operator in Canada, should build, own and operate two major pipelines for LNG projects: the 650 km-long Coastline GasLink Pipeline to the LNG Canada plant in Kitimat and the 900 km-long Prince Rupert Gas Transmission Project to the Pacific Northwest LNG plant, for a total cost of $9 billion. The third pipeline is proposed by Kitimat LNG to connect Summit Lake in Northeast British Columbia to the coast and the fourth would be built, owned and operated by Spectra to feed the Prince Rupert LNG project, which was put on hold in the fall 2014.

Table 4: BC major pipeline projects

Pipeline Name	Liquefaction Plant	Constructor, Owner & Operator	Length (km)	Capacity (Bcf/d)	Cost (G$2014)	Environmental Assessment
Coastal GasLink	LNG Canada	Transcanada	650	2.1 to 5	4.3	Certified
Pacific Trails	Kitimat LNG	Unknown	470	1	1.25	Certified
PRG Transmission	Pacific NorthWest LNG	Transcanada	900	2 to 3.6	5	Certified
Westcoast Connector	Prince Rupert LNG	Spectra	850	4.2	6 to 8	Certified
Eagle Mountain	Woodfibre LNG	Fortis BC	47	0.23	0.52	Under Review
PNG Looping	Undetermined	Pacific Northern Gas	525	0.6	N/A	Pre-Application

Source: CEDIGAZ & Companies' data

Thus, even if pipelines' investment will not directly be made by LNG projects proponents, the latter will have to support a high transportation cost, from the wellhead to the plant inlet. Based on company data and investment amounts, the pipeline tariff would range from $1/mmbtu to $1.4/mmbtu to transport natural gas from Northeast British Columbia to Kitimat.

3.2 Uncertainties surround procurement gas costs

Among operational expenditures, which can increase overall in case of labor and material shortage like capital expenditures, the highest uncertainty is linked to the actual cost of feed gas.

Over the past few years, several studies have pointed out the potentially high costs of a booming production of shale gas in the Western Canada Sedimentary Basin. As highlighted by the NEB in its May 2014 report, *Short-term Canadian Natural Gas Deliverability 2014-2016*[16], most of the resources of the Liard Basin, Horn River Basin, Cordova Embayment, and deeper portions of the Montney Formation are dry gas.

[16] NEB. *Short-Term Canadian Natural Gas Deliverability 2014-2016 - Energy Market Assessment*. NEB, May 2014. https://www.neb-one.gc.ca/nrg/sttstc/ntrlgs/rprt/ntrlgsdlvrblty20142016/ntrlgsdlvrblty20142016-eng.html.

In 2009, the NEB estimated[17] the average natural gas supply cost for new production at $6.5/mmbtu[18] in Western Canada, which was higher than the average Canadian price of $3.5/mmbtu this same year. However, the average cost hides important variations from a well to another: for example, estimates give a cost of $7.1/mmbtu for wells in a tight formation of southern Alberta, $3.6/mmbtu in Fort Johns in B.C. (Montney play) and $4.1/mmbtu in the Shale gas Horn river basin. Similarly, in 2012[19], the investment bank Macquarie estimated the dry Montney break-even at $ 3.2/mmbtu[20], liquids-rich Montney at $2.5/mmbtu and dry Horn-River at $ 3.7/mmbtu. The Canadian Energy Research Institute also published an assessment[21] of upstream costs in 2013 and found that a well drilled in the Montney Play in British Columbia would cost between $3.6/mmbtu[22] and $5.6/mmbtu for dry acreages, and between $2.5 and $4.7/mmbtu for liquids-rich assets. The latter study emphasized the already mentioned variations which may occur from a well to another, finding for example costs up to $12.8/mmbtu for a non-NGL producing well of the Montney play in Alberta. Thus, producing dry gas from unconventional plays might be very expensive, but first and foremost uneconomic, compared to the wholesale market prices in Canada: in 2014, the AECO-NIT price averaged $3.7/mmbtu[23] and prices are expected to stay low in the near future, according to futures contracts traded on the AECO Hub in early 2015. Companies are of course aware of these great uncertainties and LNG Canada, for example, has given a natural gas supply price estimate range between $4.9/mmbtu and $11.3/mmbtu in its project description [24](including transportation tariff to the plant).

3.3 The cost of delivering Canadian LNG

Besides capital expenditures and procurement gas costs, the total cost of delivered LNG on which Final Investment Decisions are based includes several other components. We try to provide here an assessment of the economics of a typical Western Canada liquefaction plant to determine under which market condition we can expect positive FIDs.

Assumptions

The model assumes a 12.8 mmtpa, located on Northern BC coast which produces over a 25 years period. The total cost is composed of 1) Plant Capital expenditures, 2) Plant Operational Expenditures, 3) Feed gas price at wellhead, 4) Pipeline tariff, and 5) Taxes. Economic calculations

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[17] NEB. *Natural Gas Supply Costs in Western Canada in 2009 - Energy Brief*. NEB, November 2010. http://www.neb-one.gc.ca/nrg/sttstc/ntrlgs/rprt/archive/ntrlgsspplcstwstrncnd2009_2010/ntrlgsspplcstwstrncndnrgybrf2009-eng.html.

[18] Prices are given in USD, based on the current year average exchange rate: in 2009 C$1= 0.88 USD.

[19] Macquarie Research. *Canadian LNG: The Race to the Coast*. Macquarie Private Wealth, September 10, 2012. http://www.google.com/url?sa=t&rct=j&q=&esrc=s&source=web&cd=2&ved=0CCoQFjAB&url=http%3A%2F%2Fwww.investorvillage.com%2Fuploads%2F8056%2Ffiles%2FCdn_LNG_100912.pdf&ei=XxrjVJXHJ4OxUZjdglA&usg=AFQjCNFib_YC1HZzqnqu6gsp88a-HH0Lrw&bvm=bv.85970519,d.d24&cad=rja.

[20] Prices are given in USD, based on the current year average exchange rate: in 2012 C$1= 1 USD.

[21] Dalzell, Julie. *Conventional Natural Gas Supply Costs in Western Canada*. Canadian Energy Research Institute, June 2013. http://www.ceri.ca/index.php?option=com_content&view=article&id=110:ceri-study-136-conventional-natural-gas-supply-costs-in-western-canada&catid=36:publication-pages.

[22] Prices are given in USD, based on the current year average exchange rate: in 2012 C$1= 1 USD.

[23] Prices are given in USD, based on the current year average exchange rate: in 2014 C$1= 0.91 USD

[24] LNG Canada. "LNG Canada Export Terminal - Environmental Assessment Certificate Application," October 2014. http://a100.gov.bc.ca/appsdata/epic/html/deploy/epic_project_home_398.html.

are based on these five costs, but we have to add a shipping cost to compute the total cost of delivered LNG.

In order to reflect uncertainties regarding the various costs, we propose three scenarios. The low case scenario corresponds to the minimum cost we can expect. The base case scenario is the most probable while the high case aims at reflecting the risks of costs inflation.

Net present values are computed using an 8% real discount rate.

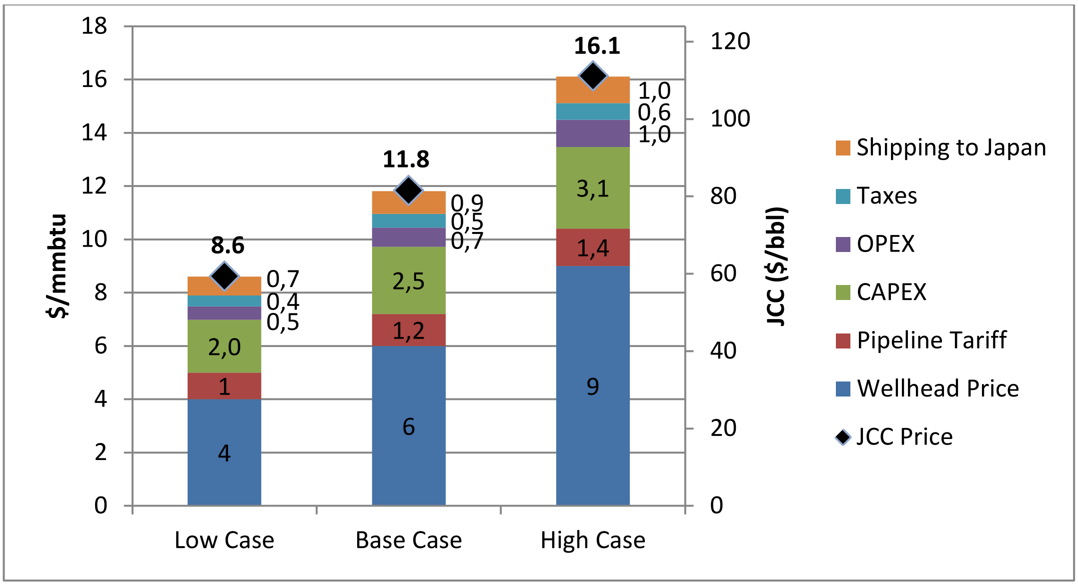
Table 5: Assumptions for the BC LNG model

	Unit	Low Case	Base Case	High Case
CAPEX	$/tpa	950	1,200	1,450
OPEX	$/t	25	35	50
Wellhead Price	$/mmbtu	4	6	9
Pipeline Tariff	$/mmbtu	1	1.2	1.4
Taxes		-Federal Corporate Tax (15%) -BC Corporate Tax (11%) -BC LNG Income Tax (Tier 1: 1.5%, Tier 2: 3% & 5%)		
Shipping to Japan	$/mmbtu	0.7	0.85	1

Results

Our base case assumptions show that the LNG price in Japan should equal $11.8/mmbtu to recover all costs. In the low case, LNG should at least be sold at $8.6/mmbtu and in the high case, it should reach $16.1/mmbtu. Assuming an average 14.5% slope for Japanese contracts indexed on the Japanese Crude Cocktail Price (JCC), Canadian LNG projects require a minimum JCC of $81/bbl with the base case assumptions. In the low case scenario, JCC break-even price for LNG projects is $59/bbl while it is up to $111/bbl in the high case.

Figure 5: DES-Japan LNG Break-even prices



These results can explain why companies have been reluctant to take a FID last year, as crude oil prices decreased sharply. In January 2015, JCC price reached $64/bbl which showed the exposure of BC projects to oil prices.

Results also show the weight of feed gas price (including the pipeline tariff) which account for about 60% of the total LNG cost on average. Economics are therefore especially sensitive to changes in procurement gas costs, which contain high uncertainties, as we mentioned previously: at least they account for 45% and at most for 75%. As for the facility cost, it equals for about 35% of the total cost on average: in the base case scenario, the liquefaction plant costs (CAPEX, OPEX and Taxes) equal $4.6/mmbtu. Our calculation emphasizes the role of the incentive fiscal policy implemented by Canada and British Columbia. The reduction of the tier-2 BC LNG tax rate after 2037 from 7% as initially planned to 5% and the accelerated Capital Cost Allowance rate for LNG equipment from 8% to 30% (on a declining balance basis) provide a $0.25/mmbtu reduction over the total break-even price with the base case assumptions. It represents a 22% decrease of tax paid per mmbtu and a 4% reduction in facility break-even per mmbtu.

Table 6: BC LNG Break-even Prices Summary ($/mmbtu)

Procurement costs / Liquefaction, shipping & taxes	Low case - 5	Base case - 7.2	High case - 10.4
Low case - 3.6	8.6	10.8	14
Base case - 4.6	9.6	11.8	15
High case - 5.7	10.7	12.9	16.1

3.4 Harsh competition with US Henry-Hub indexed contracts

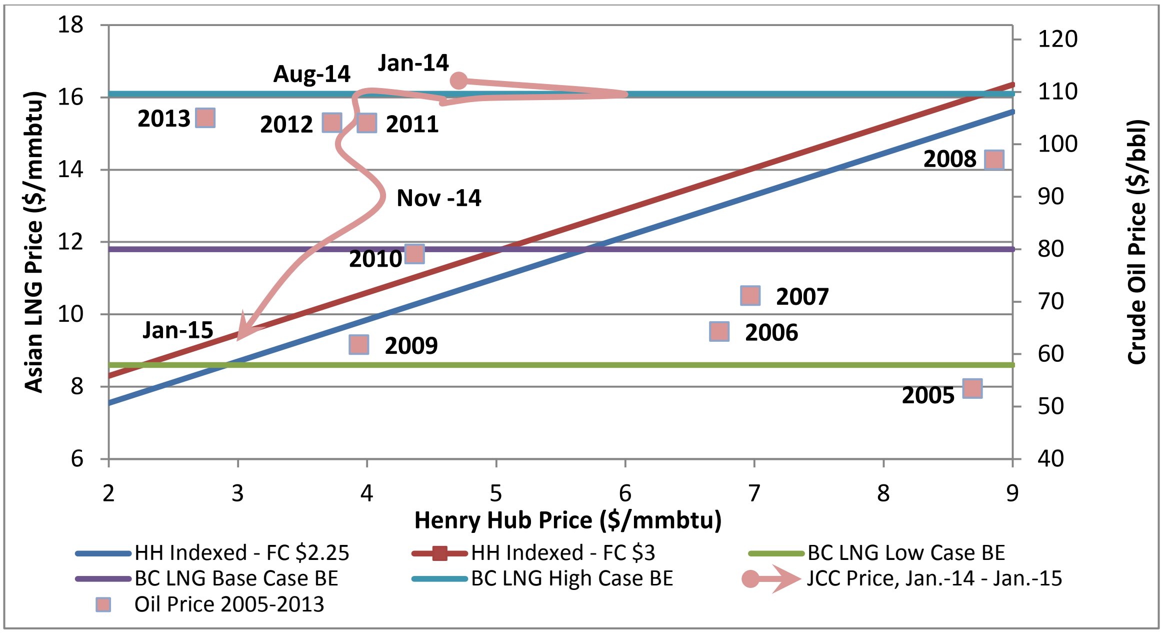
In addition to uncertainties about the economics and legal issues, the continuous postponement of Final Investment Decisions also reflects the difficulties to commercialize the gas. Without off-takers for the LNG, whether they are equity owners or contracted buyers, sponsors are not able to commit to building their project. Targeting Asian buyers, British Columbian projects are facing competition from other regions as well as pipeline projects from Russia or Central Asia to China.

In particular, when oil prices were high, the Henry Hub price indexation of US-produced LNG would have offered more attractive prices for buyers. For example, Sabine Pass contracts, which are priced 115% of Henry Hub (HH) plus a fixed sales charge of US$2.25-3.00/mmbtu, would have resulted in FOB sales price in the range of $7.3 to $8.1/mmbtu, on average in 2014, based on an average HH price of $4.4/mmbtu this same year. Assuming a shipping cost from the Gulf of Mexico (GoM) to Japan of $3.0/mmbtu, the total DES price would have ranged between $10.3/mmbtu and $11.05/mmbtu while a 14.5% slope indexation on JCC based on 2014 JCC average price of $105/bbl would have yielded a LNG DES price of $15.2/mmbtu.

Figure 6 illustrates the competitive position of oil-indexed LNG contracts with a 14.5% oil slope versus HH-indexed Sabine Pass contracts. The two diagonal lines represent the range of HH and oil prices for which both types of contracts are on par for a delivery to Japan, assuming a liquefaction fee between $2.25/mmbtu (bottom diagonal line) and $3/mmbtu (upper diagonal line). Below these lines, oil-indexed contracts are more competitive than Sabine Pass contracts, above these lines, they are less competitive, and between those lines they are more or less equal. The three horizontal lines show the required oil-price / LNG delivered price needed for West Coast Canadian projects to break-even in our three scenarios. We see that, for an oil price of around $80/bbl, needed to break-even in the base case, the HH, would have to be in the range of $4.9-$5.5/mmbtu or higher for Canadian projects to be competitive with GoM brownfield projects. At $60/bbl, an HH at $2.3- $3/mmbtu is enough for Canadian projects to compete if they can manage to break-even at that price level but if oil is back to $110/bbl, as in the first half of 2014, the Henry hub would need to reach at $8.7 to $9.3/mmbtu.

The pink squares on the chart show the historical oil and HH average annual prices between 2005 and 2014. With the exception of 2008, we can see that the oil prices have been either too low for the BC LNG projects to break-even in our base case or too high relative to the HH for these projects to compete with brownfield GoM projects. The challenge for BC LNG projects is therefore to combine profitability and competitiveness with US LNG projects. This is perfectly illustrated by the pink curve showing the JCC/HH price evolution through 2014, moving from a situation where BC projects would have been profitable even in the high cost case, but not competitive with HH based projects, to a situation of approximate parity with US projects but marginal profitability at best.

Figure 6: Oil-indexed vs. Henry Hub Indexed Prices



In recent years, competition with US projects has then weighted on the commercial attractiveness of Canadian projects. So far, the only project to have signed a Sales and Purchase Agreement is the East coast Goldboro LNG project in Nova Scotia, which stroke a deal with E.On Global Commodities in 2013. The LNG is due to be shipped to Europe and will be indexed on European natural gas market prices. The Douglas Channel LNG project used to have a deal with Golar LNG, but the recent change in equity makes the contract no longer valid: EDF Trading, one of the project's sponsors is now meant to off-take the 0.55 million tons produced each year. Opening projects' equity to off-takers, whether they own regasification capacities or they are LNG traders, has become a way for initial proponents to ensure an outlet for the plant's output. Petronas Pacific Northwest LNG has sold for example 38% of the equity to regasification capacities owners, such as JAPEX (10%), which is planning to regasify its 1.2 mmtpa equity share in its Soma LNG terminal in Japan. The other partners are Sinopec (15%), Indian Oil Corp. (10%) and Petroleum Brunei (3%). Similarly, LNG Canada opened the project equity to CNPC (20%), KOGAS (15%), and Mitsubishi Corp. (15%).

4. An assessment of Canadian LNG projects

In this complex environment, assessing the chance for projects to succeed is challenging all the more as the status of a given project can experience rapid changes. One good example of this is the Kitimat LNG project that was once leading the pack before being seriously undermined by Apache's withdrawal but that could now be put back in the saddle thanks to Woodside. Based on 6 objective criteria, CEDIGAZ has ranked the various projects into three categories. The first comprises only the front-runners, i.e. the projects that have the best chance to reach FID. The second group is composed of projects which are less advanced, but still have some chances to succeed. The third and last group contains the projects with the least chance of success as things currently stand.

4.1 Methodology and criteria

The engineering phase. Before reaching FID, a project goes through successive conception stages: the feasibility study is the preliminary stage, it is followed by Pre-FEED and FEED. The engineering phase is an objective indication of the maturity of the project in terms of conceptual and process design.

The sales criterion evaluates the commercial credibility of a project. The commercialization level can be low, medium or high. A project does not necessarily need to sign Sales and Purchase Agreements (SPA) to be credible: opening the Joint Venture to LNG off-takers is an efficient way to ensure a market for the plant's output. Projects usually need to secure off-take for 70 to 80% of their output before reaching FID.

The environmental assessment is mandatory for energy projects in Canada, and proponents have to initiate the process which can last for two years, depending on the complexity of the project and public comments. A substitution tool allows proponents to ask for the provincial agency in charge of environmental assessments to conduct the evaluation instead of the federal agency.

The export authorization is also mandatory but is usually granted without difficulties within six months. Some projects, though, have provided incomplete applications and have to reapply.

The need to build a pipeline involves additional costs, potential difficulties with land owners and First Nations and overall, longer lead times. Therefore, being able to make use of existing transport infrastructure provides a competitive advantage.

The sponsors' experience is a key criterion to evaluate the credibility of a project. Building a LNG plant is not only money issue. It is also a matter of technical and project management experience, as projects can quickly become more complex and face unexpected challenges.

4.2 The front-runners

The front-runners group is composed of three B.C. projects and of the Nova Scotia Goldboro LNG project.

Table 7: The front-runners

	Province	FID	Engineering	Sales	EA	Export License	Pipeline	Experience
Pacific NorthWest LNG	B.C.	2015	FEED	High	Under Review	Approved	Yes	High
LNG Canada	B.C.	2016	FEED	High	Under Review	Approved	Yes	High
Goldboro LNG	N.S.	2016	FEED	Medium	Approved	Under review	No	Low
Douglas Channel LNG	B.C.	2015	FEED	High	Not required	To re-apply	No	Low

Source: CEDIGAZ LNG Databases

Pacific NorthWest LNG

First expected to make a FID by the end of 2014, Pacific NorthWest LNG Partners postponed it to continue to review the economic viability of the project at a time of declining oil prices. Other reasons that had already caused delays were that new B.C. LNG income tax regime was long to be approved and because environmental concerns were brought up by First Nations during the environmental review. In October 2014, the venture proposed a new design for marine installation to satisfy with the complaints. Despite these impediments, the project still has precious competitive advantages, including equity owners who are also off-takers with regasification capacities, and a heavy experience in the LNG industry. The acquisition of Progress Energy in 2012 also provided Petronas with large gas resources in the North Montney. In 2013, Proved + Probable Reserves were estimated at 2.34 Tcf and best estimates of contingent resources (2C) at 19.9 Tcf. The project is targeting FID in June 2015.

LNG Canada

The LNG Canada project is proposed by a Shell-led joint venture, which also includes important LNG buyers such as Petrochina (20%), Mitsubishi Corp. (15%) and Kogas (15%). The project has many assets, including Shell's large experience, off-takers among the shareholders and the fact that it has already been through the environmental assessment process. Just as for the other projects, investment costs remain a big issue since the consortium evaluates the cost of the sole 24 mmtpa plant (at full build-out – the first phase only includes two 6 mmtpa trains) in range of $23 to $36 billion. According to the proponents, the project is on track and FID could be taken in 2016, after all studies are completed.

Goldboro LNG

On the East Coast, the Goldboro LNG is leading the race and has good chances to be the first plant to export LNG out of Canada. Unlike the large BC projects, the plant is planning to export US-produced natural gas to be transported through the Maritimes and Northeast pipeline. This enables the proponents to avoid upstream development and pipeline construction issues. Despite of the lack of LNG experience of Pieridae Energy, the proponent, it is the only Canadian project to have signed a Sales and Purchase Agreement: in 2013, E.On Global Commodities committed to buy 4.5 mmtpa to export to Europe over 20 years. A key issue will be the decision to authorize Pieridae to import US natural gas for export purposes. The company filed an application in October 2014 which is currently under review. The application has raised concerns among environmentalists who fear the indirect construction or expansion of pipelines (despite the fact that Pieridae is planning to use existing facilities). Regardless of what the US department of Energy decides, Pieridae announced it would take a FID on train 1 in early 2016.

Douglas Channel LNG

After the take-over by a consortium composed of Exmar, Altagas, Idemitsu and EDF Trading, which solved troubles among initial equity owners, the Douglas Channel LNG project has joined the group of front-runners. The 0.55 mmtpa project benefits from Exmar experience in liquefaction barge construction, the ability to use the existing Altagas-owned Pacific Northern Gas (PNG) pipeline and EDF Trading's role as the off-taker. Due to the small hydrocarbon storage capacity, the project falls under the threshold for an environmental assessment. Partners still have to re-apply for an export license, but it is not the critical path, according to Exmar.

4.3 The challengers

This second group comprises projects which cannot be considered as front-runners for various reasons, but which still have a chance to come on-stream sooner or later.

Table 8: The challengers

	Province	FID	Engineering	Sales	EA	Export License	Pipeline	Experience
Kitimat LNG	B.C.	2018	FEED	Low	Approved	Approved	Yes	High
Woodfibre LNG	B.C.	2015	Feasibility	Medium	Under Review	Approved	No	Low
WCC LNG	B.C.	2017	Feasibility	Low	Pre-App.	Approved	Yes	High
Aurora LNG	B.C.	2017	Feasibility	Low	Pre-App.	Approved	Yes	Medium
Canaport LNG	N.S.		Pre-FEED	Low	NA	Under Review	No	High
Triton FLNG	B.C.		Feasibility	Low	NA	Approved	No	Low
Prince Rupert LNG	B.C.	2017	Feasibility	Low	Pre-App.	Approved	Yes	High

Source: CEDIGAZ LNG Databases

Kitimat LNG

Kitimat LNG has led the BC LNG race for a while. However, the Chevron-led project was stopped by the decision of Apache, the other initial partner, to withdraw from the project. In December 2014, the latter announced the sale of its 50% share in the joint-venture to Woodside, which is expected to be closed at the end of Q1 2015. This sale could signal a new start for the project, but partners will have to contract sales with buyers and/or to open the project's equity to off-takers if they want to move forward. Given the current market conditions, this is not going to be an easy task, even though Woodside's LNG marketing experience and portfolio buyers brings a new strength to the project. Kitimat LNG plant and pipelines environmental assessments have been approved and the venture has been granted a 10 mmtpa over 20 years export license.

Woodfibre LNG

Woodfibre LNG is a small scale project backed by the Singaporean company Pacific Oil & Gas. It has secured an export license and its environmental assessment is currently in progress. Conceptual design is still at the feasibility engineering stage, but the preferred design proposes the placement of a permanently moored near shore FLNG barge with a 2.1 mmtpa capacity. It is therefore still at early stage of development but the Pacific Oil & Gas regasification capacity in the Chinese Jiangsu Rudong terminal and the plan to connect the liquefaction facility to the existing Fortis B.C. grid (requiring a 52 km long pipeline expansion) provide the project with some strengths.

WCC LNG

ExxonMobil, which is proposing to build, own and operate the WCC LNG plant in Prince Rupert along with Imperial Oil (of which 69.6% of shares in held by ExxonMobil) is the last major which has come up with a project in 2012. The project has already received authorization to export but is still at the early stage of design. In the project description provided with the application to the BC Environmental Assessment office in January 2015, ExxonMobil proposes a plant with a 15 mmtpa capacity which could be extended to 30 mmtpa. The company is currently studying two concepts, including floating near shore barges and an onshore plant. It is also planning to submit another application for a future pipeline which would bring natural gas from the WCSB, where Imperial Oil and ExxonMobil own very large resources. At the end of 2012, the two companies were holding 340,000 acres in the Horn River Shale gas play, 545,000 acres in the Montney Play and 104,000 acres in the Duvernay shale. Net developed and undeveloped reserves of Imperial Oil had been established at 0.5 Tcf at the end of 2012. Thus, the project benefits from numerous assets and is moving forward, but it is unclear whether it would be able to catch up with the front-runners, especially in terms of LNG marketing.

Aurora LNG

The Aurora LNG project can also be added to this category since it has recently been making progresses. The project is supported by Nexen (an affiliate of CNOOC), Inpex and JGC. This alliance provides a good combination of expertise in engineering and construction, but also opportunities to commercialize the LNG. The joint venture has already obtained the export authorization and has filed an application for the environmental review. In January 2015, it changed its proposed location to the Digby Island near Prince Rupert. The plant would include two 5 to 6 mmtpa trains during the first phase, starting in 2023, which may double to a total 20 to 24 mmtpa depending on market conditions, economics and the labor market.

Canaport LNG

Canaport LNG is currently operating as an import terminal in Nova Scotia and was the sole LNG assets Shell did not buy when it took over Repsol's LNG portfolio in January 2014. Repsol had earlier last year announced that it was evaluating the opportunity of converting the terminal into a liquefaction plant. Canaport LNG is the only truly brownfield project in Canada (although some other projects are located on industrial sites with some limited infrastructure). It made a new move in February 2015 when it filled an export license application to the NEB for a volume of 5 mmtpa. Natural Gas would be imported from the US Shale gas production via the Northeast and Maritime pipelines. In addition, the project could be an outlet for Talisman Energy's Marcellus production, which Repsol is going to acquire through the takeover of the Canadian company announced in December 2014.

Triton LNG

Triton LNG is a joint-venture composed of Altagas and Idemitsu, which are partnering in the Douglas Channel LNG project. The project is still at early stage of development but has already gained a license to export 2.3 mmtpa over 25 years. It is proposing to use a liquefaction barge and Altagas hopes that Douglas Channel LNG experience will prove out the concept to potential future customers. Triton LNG may also benefit from Altagas' ownership of the PNG pipeline system and from Idemitsu's, Japan's second biggest oil company, experience in selling oil. Since the take-over of Douglas Channel LNG, the joint-venture presents the two projects as part of a two phased approach. Both projects would get their gas from the PNG pipeline. Douglas Channel LNG which does not need an expansion of the pipeline would come first, while Triton LNG, which would require a 525 km pipeline expansion, could follow.

Prince Rupert LNG

For a while, BG's Prince Rupert LNG project was considered as a serious proposal for British Columbia exports, mainly because of BG's large experience in the LNG Business. In October 2014, the British company announced that it put on hold the project until it knows, among others, how much the United States are going to export. In case the project resumes, the plant would be built in Prince Rupert and receive gas from a pipeline to be built and operate by Spectra Energy. BG has initiated the various authorization processes, including the environmental review but it has not been able to find other investors to team-up with. Despite its large customer's network, BG would also need to secure contracts before adding any further LNG in its portfolio. BG has signed agreements to buy 5.5 mmtpa from the Sabine Pass LNG and has an agreement with Energy Transfer to use the whole capacity of the Lake Charles LNG project.

4.4 The speculative projects

CEDIGAZ ranks in this category all the projects which are considered as speculative, which means that they have very little chance to succeed, in the current state of the market and advancement of the project.

Table 9: The speculative projects

	Province	FID	Engineering	Sales	EA	Export License	Pipeline	Experience
Bear Head LNG	N.S.	2016		Low	Not required	Under review	No	Low
Discovery LNG	B.C.	2017	Feasibility	Low		Under review	Yes	Low
GNL Quebec	Q.C.		Feasibility	Low		Under review	Yes	Low
Grassy Point LNG	B.C.	> 2017	Feasibility	Low	Pre-App.	Approved	Yes	High
Haisla Cedar	B.C.			Low		Under review	Yes	Low
H-Energy LNG	N.S.		Feasibility	Low			No	Low
NewTimers Energy	B.C.			Low		Under review	Yes	Low
Kitsault Energy	B.C.			Low			Yes	Low
Orca LNG	B.C.		Feasibility	Low		Under review	Yes	Low
Steelhead LNG	B.C.	2018	Pre-FEED	Low		Under review	Yes	Low
Stewart Energy	B.C.		Feasibility	Low		Incomplete	Yes	Low

Source: CEDIGAZ LNG Databases

Grassy Point LNG

Back in 2014, the Woodside Grassy Point LNG project would have been ranked among challengers. However, Woodside has since acquired Apache’s stake in Kitimat LNG and it seems very likely that Woodside will focus on the latter, rather than on Grassy Point LNG, for which it is the sole proponent and does not have associated resources.

Bear Head LNG

The Bear Head LNG project was proposed in August 2014 by the Australian LNG Limited company, which develops several projects around the world, including the Fisherman’s Landing LNG project in Australia and the Magnolia LNG project in the United States. However, none of them has come to a FID yet. The company is proposing an 8 mmtpa plant using its wholly-owned liquefaction process (LNG Ltd OSMR) on the Bear Head site in Nova Scotia, where Anadarko, the previous owner, initially planned to build a regasification terminal. The latter was approved by the Canadian Environmental Evaluation Agency which enables the project to skip the review process. Natural gas would be imported from the United States through the Northeast and Maritime Pipelines. Of course, Bear Head is at early stage of development, but it is also late compared to similar proposals and doubts can be raised regarding the ability of LNG Limited to bring the project to success.

Discovery LNG

Discovery LNG is a project proposed by the US small-cap Quicksilver Resources to build a LNG plant in Campbell River, British Columbia. The company has applied for a 20 mmtpa export license which is currently under review, but no further details are given on the project’s website regarding the capacity of the plant. Quicksilver resources own about 0.27 Tcf of proved developed and undeveloped gas reserves in Canada and other assets in the United States. But the company is facing significant indebtedness issues. It was delisted from the New-York stock exchange in January 2015 and is at serious risks of going bankrupt.[25]

GNL Quebec

GNL Quebec is the first project to be proposed in the French-speaking Province. Sponsors are two investment companies, Freestone and Breyer Capital, which investigate the opportunity to develop a 5 mmtpa plant in the Port of Saguenay. This represents a $6.3 billion dollars investment and the proponents have recently applied for an export license which is currently under review. The company would liquefy gas produced by third-parties in the WCSB and transported to Quebec via the Transcanada Eastern Triangle Pipeline project.

Haisla Cedar LNG

Haisla Cedar LNG is a project owned by Haisla First Nation and unknown third parties. The only information publicly available can be found in the three separate export license applications filed in September 2014. These applications represent a total amount of 14.5 mmtpa and the project could include up to 6 liquefaction barges.

H-Energy LNG

H-Energy LNG is a project proposed by a subsidiary of the Indian Hiranandani Group in Nova Scotia, which is also proposing to build the H-Gas LNG Gateway regasification project in the state of Maharashtra on the Western Coast of India. The proponent is still studying the feasibility of the project and has not applied yet for an export permit.

Kitsault LNG

Kitsault LNG is a project proposed by an Indian-born entrepreneur, Mr. Krishnan Suthanthiran, who wants to build a 20 mmtpa liquefaction plant in the abandoned mining town of Kitsault, not far from the Alaskan border. In April 2014, he applied for an export license and has announced in January 2015 that the project was the first Canadian project to have taken a positive final investment decision. But this statement may be slightly misleading as it came with many caveats: actual investment will depend on sales contracts, regulatory reviews and agreements with First Nations, none of which has been secured yet. At this stage Kitsault LNG is “just another project”.

Orca LNG

Orca LNG is more a standalone application to the NEB than a real liquefaction project. No further information has been disclosed than the six floating liquefaction barges to be moored in near Prince Rupert mentioned in the 25 mmtpa application. The latter has been filed by a Texas-based unknown firm.

[25] “Quicksilver Resources: Should I Stay Or Should I Go?” w*ww.seekingalpha.com*, February 24, 2015. http://seekingalpha.com/article/2942856-quicksilver-resources-should-i-stay-or-should-i-go?page=2.

Steelhead LNG

Steelhead LNG, a company created on purpose to develop the eponymous project in Sarita Bay, off Vancouver. It has been working closely with the local Huu-ay-aht First Nation and has already applied for a 24 mmtpa export license. The project is progressing as it has signed in February 2015 a contract with a LNG specialist contractor WorleyParsons. The latter will be, among others, in charge of conducting the Pre-FEED work. Steelhead LNG is financially backed by Kern Partners, a Calgary-based energy sector private equity firm and does not own any gas resources, which raises serious doubts about the ability of the proponents to achieve their goal.

Stewart Energy

Stewart Energy is a company recently incorporated in British Columbia which seeks to export up to 30 mmtpa from one followed by five other liquefaction barges to be moored in Stewart, near the border of Alaska. The company is backed by Chinese investors and claims to have signed agreements with buyers, to own upstream assets and to be partnering with a third-party to build an 800 km long pipeline from the WCSB, without revealing any name. The credibility of the project can therefore be questioned, all the more than its export license application has been qualified as “incomplete” by the NEB.

Conclusion

John Watson, Chevron's CEO, clearly summed-up what is at stake for Canadian LNG project when he declared in September 2014 about Kitimat LNG: "It's not a schedule-driven project. It's an economics-driven project".

Canada is endowed with huge gas resources and, with limited domestic demand growth and dwindling pipeline exports to the United States, LNG appears the best way to monetize them. Aside from this large resource base, Canadian LNG projects benefit from the large support of stakeholders that ensures a favorable legal framework. But these advantages are partially offset by potential cost issues, due to the lack of upstream development and transport infrastructure, and by the competition with US projects that promote a model based on Henry Hub indexed flexible contracts whereas Canadian projects still rely on the traditional oil-indexed contracts to secure their investment. This situation has made it challenging for Canadian projects to secure the necessary long term commitment from LNG buyers. With the current fall in oil prices and a looming LNG glut that could last until the early 2020's, prospects have deteriorated lately.

British Columbia projects could therefore have to wait for the return of a more favorable environment with the risk of missing the train. If Final Investment Decisions are not taken soon, the Canadian LNG industry take-off could be postponed by ten years or more, as LNG projects in the United States are moving forward quickly and could meet a significant share of the global demand. In that respect, 2015 will be a pivotal year for Canadian projects.

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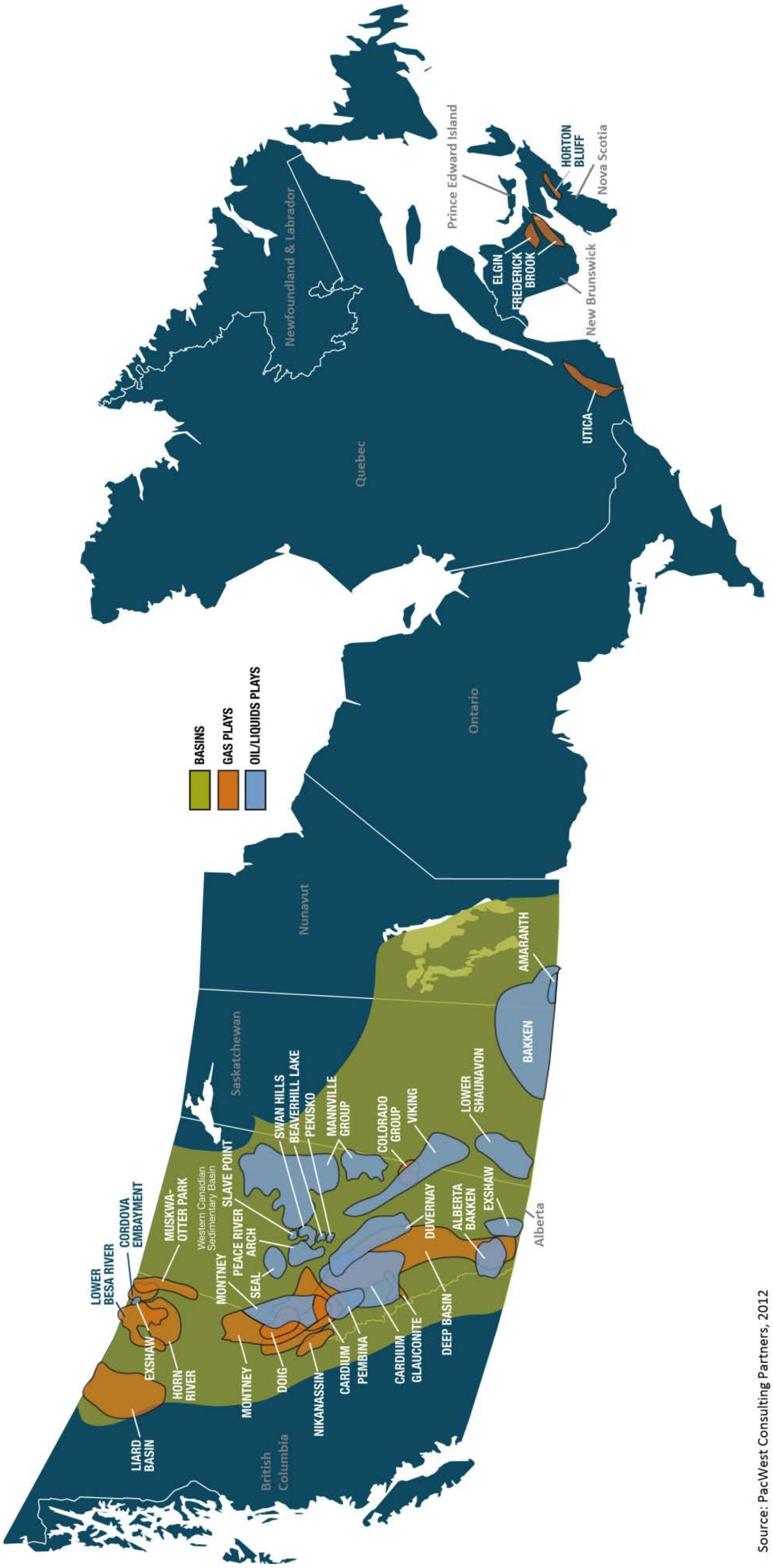
Acronyms

BCEAO	British Columbia Environmental Assessment Office
CEAA	Canadian Environmental Assessment Agency
DES	Delivery Ex-Ship
EIA	Energy Information Agency
FID	Final Investment Decision
FOB	Free On Board
GoM	Gulf of Mexico
HH	Henry Hub
JCC	Japanese Crude Cocktail
NEB	National Energy Board
SPA	Sales and Purchase Agreement
WCSB	Western Canada Sedimentary Basin

Appendix 1: Map of Hydrocarbon Resources in Canada



Source: PacWest Consulting Partners, 2012

Appendix 2: Canadian LNG Projects' Locations

LNG Projects by Area

British Columbia	Kitimat	Prince Rupert	Vancouver	Kitsault	Stewart	Campbell River
	LNG Canada	Prince Rupert LNG	Steelhead LNG	Kitsault LNG	Stewart LNG	Discovery LNG
	PacificNorthWest LNG	Grassy Point LNG	Woodfibre LNG			
	Kitimat LNG	WCC LNG				
	Douglas Channel LNG	Aurora LNG				
	Haisla Cedar	Orca LNG				
	NewTimes Energy LNG					
	Triton LNG					
Nova Scotia	**Port Hawkesbury**	**Goldboro**				
	Bear Head LNG	Goldboro LNG				
	H-Energy					
New Brunswick	**Saint-John**					
	Canaport LNG					
Quebec	**Saguenay**					
	GNL Quebec					

Source: CEDIGAZ LNG Databases

Appendix 3-1: Canadian LNG Projects' Descriptions – The Front-runners

Pacific NorthWest LNG

Sponsors	Petronas (62%) ; Sinopec (15%) ; Japex (15%) ; Indian Oil Corp. (10%) ; Petroleum Brunei (3%)	
Location	Kitimat, British Columbia	
Schedule	FID: 2015 First Gas: 2023	
Investment	G$32 (Including G$11 for the plant)	
Technical Features		
Phase 1	Liquefaction: 12.8 mmtpa - 2 trains	Storage: 360 mcm - 2 tanks
Phase 2	Liquefaction: 6.4 mmtpa - 1 train	Storage: 180 mcm - 1 tank
Engineering Phase	FEED (Triple FEED:(1) KBR / JGC ; (2) Technip / Samsung / HQCEC ; (3) Bechtel)	
Gas Supply		
Resources	20 Tcf (2P + 2C) in North Montney (owned by Petronas' affiliate Progress Energy)	
Pipeline	PRG Transport - 900 km - Certified by the BCEAO	
Regulatory Approvals		
Export License	Approved - 19.7 mmtpa over 25 years	
Env. Assessment	BCEAO's Certificate issued ; CEAA's EA in Progress	
Sales		
Off-takers' Equity Regasification Capacities in 2015:		
Petronas: 8.9 mmtpa, Sinopec: 4 mmtpa		

Source: CEDIGAZ LNG Databases

LNG Canada

Sponsors	Shell (50%) ; CNPC (20%) ; Kogas (15%) ; Mitsubishi Corp. (15%)	
Location	Kitimat, British Columbia	
Schedule	FID: 2016 First Gas: 2025	
Investment	G$23-36	
Technical Features		
Phase 1	Liquefaction: 12 mmtpa - 2 trains	Storage: 225 mcm - 1 tank
Phase 2	Liquefaction: 12 mmtpa - 2 trains	Storage: 225 mcm - 1 tank
Engineering Phase	FEED WorleyParsons / Chiyoda / Foster Wheeler / Saipem	
Gas Supply		
Resources		
Pipeline	Coastal GasLink - Certified by the BCEAO	
Regulatory Approvals		
Export License	Approved - 24mmtpa over 25 years	
Env. Assessment	BCEAO's EA in Progress (No CEAA review)	
Sales		
Off-takers' Equity Regasification Capacities in 2015:		
Shell: 5 mmtpa, CNPC: 13 mmtpa, Kogas: 130 mmtpa,		

Source: CEDIGAZ LNG Databases

Goldboro LNG

Sponsors	Pieridae Energy (100%)		
Location	Goldboro, Nova Scotia		
Schedule	FID: 2016	First Gas: 2021	
Investment	G$8.5		
Technical Features			
Phase 1	Liquefaction: 10 mmtpa - 2 trains		Storage: 690 mcm - 3 tanks
Engineering Phase	FEED	CB&I	
Gas Supply			
Resources	Third Party - US imported natural gas (DOE Export License currently under review)		
Pipeline	To use existing transborder Northeast and Maritime Pipelines		
Regulatory Approvals			
Export License	Under review - 10 mmtpa over 20 years		
Env. Assessment	Nova Scotia Environment Certificate issued (No CEAA review)		
Sales			
SPA with E.On Global Commodities: 4.5 mmtpa over 20 years to be exported to Europe			

Source: CEDIGAZ LNG Databases

Douglas Channel LNG

Sponsors	Exmar, Altagas, Idemitsu, EDF	
Location	Kitimat, British Columbia	
Schedule	FID: 2015	
Investment	G$ 0.6	
Technical Features		
Phase 1	Liquefaction: 0.55 mmtpa - 1 barge	Storage: N/A
Engineering Phase	N/A	
Gas Supply		
Resources	Third Party	
Pipeline	To use existing Altagas' Pacific Nothern Gas Pipeline	
Regulatory Approvals		
Export License	To re-apply	
Env. Assessment	N/A	
Sales		
EDF Trading will be the off-taker.		

Source: CEDIGAZ LNG Databases

Appendix 3-2: Canadian LNG Projects' Descriptions – The Challengers

Kitimat LNG

Sponsors	Chevron (50%) ; Apache (50%) (*)	
Location	Kitimat, British Columbia	
Schedule	FID: 2018	First Gas: 2026
Investment		
Technical Features		
Phase 1	Liquefaction: 11 mmtpa - 2 trains	Storage: 420 mcm - 2 tanks
Engineering Phase	FEED	KBR, completed by Fluor / JGC work
Gas Supply		
Resources	15 Tcf (2C) in the Liard and Horn River Basins	
Pipeline	Pacific Trails - 470 km - Certified by the BCEAO	
Regulatory Approvals		
Export License	Approved - 10 mmtpa over 20 years	
Env. Assessment	BCEAO's Certificate issued ; CEAA's Certificate issued	
Sales		
No off-take agreement signed and neither Chevron nor Apache/Woodside has regasification capacities.		

Source: CEDIGAZ LNG Databases

Note: (*) On December 2014, Apache announced the sale of its stake in the project to Woodside Petroleum. It is subject to regulatory approvals and would be closed by the end of Q1 2015.

Woodfibre LNG

Sponsors	Pacific Oil & Gas (100%)	
Location	Squamish, British Columbia	
Schedule	FID: 2015	
Investment	G$ 1.6	
Technical Features		
Phase 1	Liquefaction: 2.1 mmtpa - 1 barge	Storage: 170-250 mcm
Engineering Phase	Preliminary	
Gas Supply		
Resources	Third Party	
Pipeline	Eagle Mountain - 47 km - BCEAO's EA in Progress	
Regulatory Approvals		
Export License	Approved - 2.1 mmtpa over 25 years	
Env. Assessment	NA	
Sales		
Pacific Oil & Gas has a 3.1 mmtpa regasification capacity in the Chinese Jiangsu Rudong terminal (in 2015)		

Source: CEDIGAZ LNG Databases

WCC LNG

Sponsors	ExxonMobil (50%) ; Imperial Oil (50%)	
Location	Prince Rupert, British Columbia	
Schedule	FID: 2018	
Investment	G$15 to G$30 for an initial 15 mmtpa phase	
Technical Features (*)		
Full build-up	Liquefaction: 30 mmtpa - 5 trains	Storage: 1000 mcm - 5 tanks
Engineering Phase	Preliminary	
Gas Supply		
Resources	N/A	
Pipeline	To be determined	
Regulatory Approvals		
Export License	Under review - 30 mmtpa over 25 years	
Env. Assessment	BCEAO's EA Pre-Application (No CEAA review)	
Sales		
Off-takers' Equity Regasification Capacities in 2015:		
ExxonMobil: 8.5 mmtpa		

Source: CEDIGAZ LNG Databases

Note: (*) In the environmental assessment project description, proponents also write being investing a 5*6 mmtpa barge concept.

Aurora LNG

Sponsors	CNOOC (60%) ; Inpex (20%) ; JGC (20%)	
Location	Digby Island, British Columbia	
Schedule	FID: 2017	
Investment	G$15 to G$18 at full build out	
Technical Features		
Phase 1	Liquefaction: 10 to 12 mmtpa - 2 trains	Storage: 360 mcm - 2 tanks
Phase 2	Liquefaction: 10 to 12 mmtpa - 2 trains	Storage: 180 mcm - 1 tank
Engineering Phase	Preliminary	
Gas Supply		
Resources	Owners' and Third Party	
Pipeline	To be determined	
Regulatory Approvals		
Export License	Approved - 24 mmtpa over 25 years	
Env. Assessment	BCEAO's EA Pre-Application (No CEAA review)	
Sales		
Off-takers' Equity Regasification Capacities in 2015:		
CNOOC: 18.4 mmtpa, Inpex: 2 mmtpa		

Source: CEDIGAZ LNG Databases

Canaport LNG			
Sponsors	Repsol (100%)		
Location	Saint-John, New Brunswick		
Schedule	FID: N/A		
Investment	G$ 3.6		
Technical Features			
Phase 1	Liquefaction: 5 mmtpa - 1 train		Storage: 540 mcm - 3 tanks (Exisiting)
Engineering Phase	Pre-FEED	Repsol SJLNG	(Conversion of the existing import terminal)
Gas Supply			
Resources	Third Party - Supplied from the WCSB and/or the Appalachia		
Pipeline	N/A		
Regulatory Approvals			
Export License	Under Review - 5 mmtpa over 25 years		
Env. Assessment	N/A		
Sales			
None			

Source: CEDIGAZ LNG Databases

Triton LNG		
Sponsors	Altagas (50%) ; Idemitsu (50%)	
Location	Prince Rupert or Kitimat, British Columbia	
Schedule	FID: 2016	
Investment	N/A	
Technical Features		
Phase 1	Liquefaction: 2.3 mmtpa - 1 barge	Storage: 200 mcm
Engineering Phase	Preliminary	
Gas Supply		
Resources	Third Party	
Pipeline	Triton LNG Pipeline, connecting with PNG pipeline - 525 km - No EA Application	
Regulatory Approvals		
Export License	Approved - 2.3 mmtpa over 25 years	
Env. Assessment	No Application	
Sales		
None		

Source: CEDIGAZ LNG Databases

Prince Rupert LNG

Sponsors	BG (100%)	
Location	Prince Rupert, British Columbia	
Schedule	FID: Delayed *Sine Die*in October 2014	
Investment	G$16	
Technical Features		
Phase 1	Liquefaction: 14 mmtpa - 2 trains	Storage: 360 mcm - 2 tanks
Phase 2	Liquefaction: 7 mmtpa - 1 train	Storage: 225 mcm - 1 tank
Engineering Phase	Preliminary	
Gas Supply		
Resources	N/A	
Pipeline	Westcoast Connector - Certified by the BCEAO	
Regulatory Approvals		
Export License	Approved - 22mmtpa over 25 years	
Env. Assessment	BCEAO's EA Pre-Application, CEEA's EA in Progress	
Sales		
Off-takers' Equity Regasification Capacities in 2015:		
BG: 3.8 mmtpa		

Source: CEDIGAZ LNG Databases

Appendix 3-3: Canadian LNG Projects' Descriptions – The Speculative Projects

Bear Head LNG

Sponsors	LNG Limited (100%)	
Location	Bear Head, Nova Scotia	
Schedule	FID: 2016	
Investment	NA	
Technical Features		
Phase 1	Liquefaction: 4 mmtpa - 2 trains	Storage: 360 mcm - 2 tanks
Phase 2	Liquefaction: 4 mmtpa - 2 trains	
Engineering Phase	Preliminary	
Gas Supply		
Resources	Third Party - US imported natural gas	
Pipeline	To use existing transborder Northeast and Maritime Pipelines	
Regulatory Approvals		
Export License	Under Review - 12 mmtpa over 25 years	
Env. Assessment	No Application	
Sales		
None		

Source: CEDIGAZ LNG Databases

Discovery LNG

Sponsors	Quicksilver Resources (100%)	
Location	Campbell River, British Columbia	
Schedule	FID: 2017	
Investment	N/A	
Technical Features		
Phase 1	Liquefaction: 5 mmtpa - 1 train	Storage: N/A
Engineering Phase	Preliminary	
Gas Supply		
Resources	Owner's Horn River Resources	
Pipeline	To be determined	
Regulatory Approvals		
Export License	Under Review - 20 mmtpa over 25 years	
Env. Assessment	No Application	
Sales		
None		

Source: CEDIGAZ LNG Databases

GNL Quebec

Sponsors	Freestone ; Breyer Capital	
Location	Saguenay, Quebec	
Schedule	FID: N/A	
Investment	G$ 6.3	
Technical Features		
Phase 1	Liquefaction: 11 mmtpa - 3 trains	Storage: 400 mcm - 2 tanks
Engineering Phase	Preliminary	
Gas Supply		
Resources	Third Party - Supplied from the WCSB via Transcanada's Eastern Triangle Pipeline	
Pipeline	GNLQ Pipeline, connecting with Transcanada's pipeline - 650 km - No EA Application	
Regulatory Approvals		
Export License	Under Review - 11 mmtpa over 25 years	
Env. Assessment	No Application	
Sales		
None		

Source: CEDIGAZ LNG Databases

Grassy Point LNG

Sponsors	Woodside (100%)	
Location	Grassy Point, British Columbia	
Schedule	FID: 2017	
Investment	G$9 to G$13.5 for an initial 6 to 15 mmtpa phase	
Technical Features		
Phase 1	Liquefaction: 6 to 15 mmtpa	Storage: 360 mcm to 540 mcm - 2 to 3 tanks
Phase 2	Liquefaction: Up to a total of 20 mmtpa	
Engineering Phase	Preliminary	
Gas Supply		
Resources	N/A	
Pipeline	To be determined	
Regulatory Approvals		
Export License	Approved - 20 mmtpa over 25 years	
Env. Assessment	BCEAO's EA Pre-Application (No CEAA review)	
Sales		
None		

Source: CEDIGAZ LNG Databases

Haisla Cedar LNG

Sponsors	Haisla First Nation ; Unknown third-parties	
Location	Douglas Channel, British Columbia	
Schedule	FID: N/A	
Investment	N/A	
Technical Features		
Phase 1	Liquefaction: 5 mmtpa - 2 barges	Storage: N/A
Phase 2	Liquefaction: 5 mmtpa - 2 barges	
Phase 3	Liquefaction: 5 mmtpa - 2 barges	
Engineering Phase	Preliminary - May use Golar LNG's Liquefaction Vessels	
Gas Supply		
Resources	Third Party	
Pipeline	To be determined	
Regulatory Approvals		
Export License	Under Review - 14.5 mmtpa over 25 years	
Env. Assessment	No Application	
Sales		
None		

Source: CEDIGAZ LNG Databases

H-Energy

Sponsors	H-Energy	
Location	Melford, Nova Scotia	
Schedule	FID: N/A	
Investment	G$ 3.1	
Technical Features		
Phase 1	Liquefaction: 4.5 mmtpa - 1 train	Storage: N/A
Phase 2	Liquefaction: 9 mmtpa - 2 trains	Storage: N/A
Engineering Phase	Preliminary	
Gas Supply		
Resources	Third Party - US imported natural gas ?	
Pipeline	N/A	
Regulatory Approvals		
Export License	No Application	
Env. Assessment	No Application	
Sales		
None		

Source: CEDIGAZ LNG Databases

NewTimes Energy LNG		
Sponsors	NewTimes Energy (100%)	
Location	Prince Rupert, British Columbia	
Schedule	FID: N/A	
Investment	N/A	
Technical Features		
Phase 1	Liquefaction: 12 mmtpa - 3 trains	Storage: N/A
Engineering Phase	Preliminary	
Gas Supply		
Resources	N/A	
Pipeline	N/A	
Regulatory Approvals		
Export License	Under review - 12 mmtpa over 25 years	
Env. Assessment	No Application	
Sales		
None		

Source: CEDIGAZ LNG Databases

Kitsault LNG		
Sponsors	Kitsault Enery (100%)	
Location	Kitsault, British Columbia	
Schedule	FID: N/A	
Investment	G$ 3.1	
Technical Features		
Phase 1	Liquefaction: 8 mmtpa - 2 barges	Storage: N/A
Phase 2	Liquefaction: 12 mmtpa - 2 trains	Storage: N/A
Engineering Phase	Preliminary	
Gas Supply		
Resources	Third Party - Supplied from the WCSB via Spectra Transmission System	
Pipeline	To be built from Mackenzie, British Columbia - No EA Application	
Regulatory Approvals		
Export License	No Application	
Env. Assessment	No Application	
Sales		
None		

Source: CEDIGAZ LNG Databases

Orca LNG

Sponsors	Orca LNG (100%)	
Location	Prince Rupert, British Columbia	
Schedule	FID: N/A	
Investment	N/A	
Technical Features		
Phase 1	Liquefaction: 24 mmtpa - 6 barges	Storage: 1500 mcm
Engineering Phase	Preliminary	
Gas Supply		
Resources	Third Party	
Pipeline	N/A	
Regulatory Approvals		
Export License	Under Review - 24 mmtpa over 25 years	
Env. Assessment	No Application	
Sales		
None		

Source: CEDIGAZ LNG Databases

Steelhead LNG

Sponsors	Steelhead Group (100%)	
Location	Sarita Bay, British Columbia	
Schedule	FID: N/A	
Investment	G$ 30	
Technical Features		
Phase 1	Liquefaction: 24 mmtpa - 4 trains	Storage: N/A
Phase 2	Liquefaction: 6 mmtpa - 1 train	Storage: N/A
Engineering Phase	Pre-FEED WorleyParsons	
Gas Supply		
Resources	Third Party - Supplied from the WCSB via Spectra Transmission System	
Pipeline	To be built from Northern British Columbia - No EA Application	
Regulatory Approvals		
Export License	Under review - 30 mmtpa over 25 years	
Env. Assessment	No Application	
Sales		
None		

Source: CEDIGAZ LNG Databases

Stewart Energy		
Sponsors	Stewart Energy (100%)	
Location	Stewart, British Columbia	
Schedule	FID: N/A	
Investment	G$ 3.1	
Technical Features		
Phase 1	Liquefaction: 25 mmtpa - 5 trains	Storage: N/A
Phase 2	Liquefaction: 5 mmtpa - 1 train	Storage: N/A
Engineering Phase	Pre-FEED WorleyParsons	
Gas Supply		
Resources	Third Party - Supplied from the WCSB via Spectra Transmission System	
Pipeline	To be built from Northern British Columbia - 800 km - No EA Application	
Regulatory Approvals		
Export License	Incomplete - 30 mmtpa over 25 years	
Env. Assessment	No Application	
Sales		
None		

Source: CEDIGAZ LNG Databases

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