Studies in
ENERGY POLICY

October 2012

Laying the Groundwork for BC LNG Exports to Asia

by Gerry Angevine and Vanadis Oviedo

Key findings

- Enormous quantities of natural gas have been identified in tight sand and shale formations in northeast British Columbia during the past decade. The potential supply of recoverable, marketable gas is much greater than western Canadian requirements. Further, opportunities for Canadian gas exports to the United States are shrinking.

- Demand for liquefied natural gas (LNG) is increasing rapidly in Japan, South Korea, Taiwan, China, and other countries in the Asia-Pacific region where it can be sold at a premium compared to the Canadian price of gas. This represents a substantial window of opportunity for British Columbia LNG project developers, but they must act quickly because of competition from Australian, US, and Middle Eastern LNG suppliers.

- Construction and operation of natural pipelines from northeast British Columbia to Kitimat and other west-coast ports, and of the gas liquefaction and terminal facilities, together with the greatly expanded natural gas production would contribute very significantly to employment, labour income, and GDP in British Columbia and the rest of Canada.

- The BC government recognizes the economic benefits that would accrue from exporting LNG and issued an LNG strategy document in February 2012. However, existing outdated regulatory processes and procedures, unnecessary duplication of federal and provincial government project reviews, and an unwieldy environmental review process could impede the timely development of a Canadian LNG export industry. If the federal and BC governments believe it is important to secure a niche for British Columbia's gas resources in the Asia-Pacific market, they should consider introducing reforms to streamline the regulatory approval process and thereby expedite development.

Studies in
Energy Policy

October 2012

Laying the Groundwork for BC LNG Exports to Asia

by Gerry Angevine and Vanadis Oviedo

Summary

British Columbia could benefit greatly by exporting liquified natural gas (LNG) to the Asia-Pacific Region. However, opposition by special-interest groups, out-dated, cumbersome, and overlapping regulations, along with other non-market factors, are inhibiting the development of the pipelines and terminal facilities required to ship LNG from Canada's west coast to Japan, Korea, China, India, and other Asian countries.

This study estimates the economic opportunities for British Columbia that would flow from exports of liquified natural gas to Asian and Pacific markets, and explores how existing obstacles to infrastructure development could be overcome, to enable Canada to take full advantage of opportunities to develop important alternative markets for natural gas.

Contents

Overview / iii

Introduction / 1

Production, reserves, and exports of natural gas in British Columbia / 3

Prospects for natural gas demand in the Asia-Pacific region / 12

The opportunity cost of confining gas exports to US markets / 16

Gross economic impacts from access to Asia-Pacific LNG markets / 20

Obstacles to LNG exports from British Columbia / 31

Policy options / 43

References / 50

About the authors / 57

Publishing information / 58

Supporting the Fraser Institute / 59

Purpose, funding, & independence / 60

About the Fraser Institute / 61

Editorial Advisory Board / 62

Overview

Use of Liquified Natural Gas (LNG) has been growing rapidly in the Asia-Pacific region, mainly as an energy source for electric generation but also for distribution to residential, commercial, and industrial consumers. Growth in LNG use has been strongest in Japan, Korea, and Taiwan, which together accounted for 86% of Asia-Pacific LNG trade in 2009. China and India, which are also becoming important LNG markets, represented 13% of LNG trade in the region in 2009 but are expected to account for an even greater share in coming years.

LNG prices in the Asia Pacific region are generally indexed to the Japan Customs Cleared price for crude oil imports, which closely follows the price of Brent (North Sea) crude oil. Because LNG prices there are approximately 90% of the oil price on an equivalent-heating-value basis, they are considerably higher than North American gas prices. LNG exports to Asia would allow Canadian gas producers to benefit from this price differential.

Until now, Canadian gas producers have only exported gas via pipeline to markets in the United States. However, it is becoming difficult to maintain (let alone grow) export volumes to the United States because US gas production has increased remarkably as the result of technologies that have made development of tight gas and shale gas resources commercially viable.[1] Moreover, this increase in the United States' domestic supply of gas has reduced gas prices and, similarly, netbacks to producers exporting gas to the United States.

Fortunately, Canadian gas producers have an opportunity to develop markets in Asia where buyers are seeking stable, long-term LNG purchase agreements with reliable gas producers in politically stable countries such as Canada.

However, a variety of policies stand to impede development of the infrastructure that will be required to export liquefied natural gas (LNG) to

1 Gas that is embedded in tight sand formations is often referred to simply as "tight gas." Natural gas locked in rock shale formations is typically known as "shale gas." The presence of natural gas in shale formations has been known for many years but only recently, with the development of horizontal drilling and hydraulic fracturing technologies, has production become feasible.

markets in the Asia-Pacific region via British Columbian ports. Most of the natural gas supplies are expected to come from northeast British Columbia, which has an immense amount of tight and shale gas resources. However, some of the gas could eventually also be brought from northwest Alberta, the southeast corner of Yukon, and other regions.

To assess the economic impacts from exporting LNG to markets in the Asia-Pacific region, we developed a development scenario compatible with the National Energy Board's most recent long-term forecast of BC natural gas production. In our development scenario, LNG exports reach 7.1 billion cubic feet per day (Bcf/day) by 2032. This assumes that the Kitimat LNG Inc. and the BC LNG Export Co-operative projects (both of which have been granted export licenses by the National Energy Board) proceed. It also assumes that LNG Canada, an LNG export facility proposed by Royal Dutch Shell, and its Korea Gas Corporation, Mitsubishi Corporation, and PetroChina Investment (PetroChina) partners, will be developed, along with two additional facilities (unidentified) that we have labeled "Project A" and "Project B."[2]

Pipelines must be built to transport natural gas to the LNG export terminals. We anticipate that the proposed Pacific Trail Pipeline will be constructed to support the Kitimat LNG project and that Pacific Northern Gas Ltd.'s current capacity will be expanded to aid transport of gas to the BC LNG Export Co-operative facility. In addition, we assume that the proposed Coastal GasLink Pipeline will be built (and later expanded) to transport gas to the LNG Canada facility and that two other pipelines will be constructed to supply the Project A and Project B LNG export facilities.

Building pipelines to transport natural gas from northeast British Columbia to the west coast for export to the Asia-Pacific region will bring substantial direct and indirect economic benefits. The construction of new gas pipelines is estimated to contribute approximately $4 billion to Canadian GDP and at least 45,000 job-years of employment.[3] The construction of LNG liquefaction and terminal facilities is estimated to create another 8,350 job years. In addition, operation of the natural gas liquefaction terminals and new and expanded pipelines will generate considerable full-time employment.

In addition to the contributions to employment and GDP from LNG exports, Canada would benefit from the increased netbacks to natural gas producers. According to the Asian LNG export scenario that we have

2 On June 28, 2012, Progress Energy Resources Corp. indicated that the company had received a purchase offer from Petronas Inc. of Malaysia and anticipates shipments from its BC LNG export project to commence by 2018 (Progress Energy, 2012). This and the September 2012 announcement by BG Group PLC that it is considering building a large LNG export facility at Prince Rupert could result in more rapid, and possibly greater, development than we assumed (Healing, 2012, September 10).

3 One job-year is equal to 1,960 hours (40 hours per week, 49 weeks per year).

outlined, these could exceed $134 billion 2010 dollars over the period from 2014 to 2035. LNG export facility development in excess of the projects and capacities that we have assumed would, of course, increase all of these benefits accordingly.

Unfortunately, cumbersome regulatory processes and procedures, opposition by some First Nations and special-interest groups, conflicting toll-setting methodologies, and often unwarranted environmental concerns and review processes are inhibiting the development of the transportation infrastructure needed to ship natural gas to the west coast. With development constrained and slowed by obstacles, much natural gas production growth will be foregone, and with it, considerable growth in GDP, labor income and employment.

If Canadians wish to reap the benefits that would accrue from timely development of British Columbia's vast tight and shale gas resources, policy reforms that reduce impediments to infrastructure development are essential. Removing obstacles also means considering the benefits from updating essential regulatory processes, including those required under the National Energy Board Act, to meet the needs of the twenty-first century. Applicable legislation and regulations governing energy project regulation may need to be reformed to ensure that, going forward, project applications can be dealt with objectively and within reasonable time periods. Clearly, repetition of the regulatory delays and economic costs witnessed in the case of the Mackenzie Gas project[4] and presently unfolding in the case of the Enbridge Northern Gateway[5] project needs to be avoided.

In particular, the authors suggest federal and provincial governments expedite development of the infrastructure that is needed to gain access to LNG markets in the Asia-Pacific region with legal and regulatory reforms and measures, and innovative approaches such as the following.

4 The Mackenzie Gas project involves the construction of gathering pipelines, processing facilities, and a major gas-transmission pipeline to transport natural gas from the Mackenzie Delta to Alberta to connect with the system of Nova Gas Transmission Ltd. The project was first proposed in the early 1970s but shelved due to Aboriginal land claims and environmental concerns. It was resurrected in 2004 when a new proposal was filed with the National Energy Board. That proposal was approved, with numerous conditions attached, in December 2010.

5 The proposed Enbridge Northern Gateway project would involve constructing twin pipelines from Bruderheim, Alberta, to Kitimat, British Columbia, and a marine terminal with storage capacity in Kitimat. The eastbound pipeline would transport to Alberta natural gas condensate (pentanes plus) that is used to reduce the viscosity of bitumen and heavy crude oil so that it may be more readily transported via pipeline. The westbound pipeline would transport crude oil, bitumen, and synthetic crude oil to a new marine terminal in Kitimat, where it would be shipped to Asian markets. Some First Nations groups and environmentalist groups are opposing the project before the National Energy Board on environmental, social, and cultural grounds. A decision is not expected before 2014.

1. Restrict the scope of the National Energy Board to matters necessary to protect the public interest such as construction and operational standards and efficiency, property rights and claims, and environmental impacts.

2. Limit the number of registered interveners at public hearings to prevent special-interest groups from "owning the mic" and prolonging the process.

3. Place shorter, more clearly defined and binding limits on the time regulators and the responsible elected officials may take to review energy project applications and reach decisions.

4. Convene generic National Energy Board hearings if two or more similar project applications are likely to be brought forward during the next 10 to 20 years.

5. Involve federal and provincial government and First Nations organizations with industry representatives to identify and approve transportation corridors to be used for infrastructure development.

6. Require a single construction application where an export terminal, facility, and a new pipeline are being proposed by the same investors.

7. Remove inconsistencies in the methodologies used to determine tolls on federally-regulated natural gas pipelines.

8. Deal with First Nations' environmental concerns under and in accordance with the Canadian Environmental Assessment Act.

9. Promulgate federal legislation and regulations to provide for mandatory settlement mechanisms to resolve compensation issues disputes with First Nations groups if and as required.

10. Encourage discussions between project proponents and First Nations well before applications are filed with the National Energy Board, a Joint Review Panel and/or other government agencies.

11. Require operators of natural gas pipelines to undertake risk assessments in relation to "high consequence areas" as part of their integrated management plans and to ensure pipelines are not operated at greater than approved pressure levels.

12 Revise regulations to require more frequent and thorough monitoring of pipeline condition and integrity in order to reduce the likelihood of failure incidents occurring.

13 Establish joint federal-provincial environmental reviews for projects requiring approvals from both levels of government, or substitute provincial environmental assessments that meet the requirements of the Canadian Environmental Assessment Act in place of federal assessments.

14 Require only a single environmental impact assessment where proposed natural gas pipelines, liquefaction plants, and export terminal facilities share the same proponent.

Introduction

Production of natural gas from tight sand and shale formations in northeast British Columbia is ramping up. However, the long-held view that the United States will continue to absorb whatever volumes of gas Canada has to export is changing. For one thing, the proliferation of shale-gas production in the United States is making it more and more difficult for Canadian gas to compete south of the border where gas prices, and therefore netbacks,[1] are likely to remain depressed for some time. Further, as explained later in this publication, the widening differential between natural gas prices in the United States and the higher value that liquefied natural gas (LNG) is able to command in Europe and Asia, means that the opportunity cost from having only a single export market for natural gas has become, and is likely to remain, substantial.

Increasing participation in the development of British Columbia's gas resources by companies from Asian countries, which will need additional natural gas supplies to fuel electric generation and help to satisfy the energy requirements of the industrial and residential sectors, indicates that they recognize the benefits from diversifying their LNG supply portfolios by being involved in the development of Canadian natural gas reserves. For example, Korea Gas Corporation, Sinopec (China Petroleum & Chemical Corporation), Mitsubishi Corporation, and PetroChina are now involved in joint ventures with Shell and with PennWest Energy and other Canadian companies in the development of shale and tight gas resources in British Columbia. Although these companies have no assurance that transportation facilities will be developed to allow LNG to be shipped to their home

1 "Netbacks" are the sales margins calculated at the point of production, that is, the price that is obtained by the seller less the cost of transportation from the source of supply to the point of delivery to the buyer. In order to obtain the highest available return on their investment, gas producers naturally desire to achieve the highest possible netbacks. If access to LNG markets in the Asia-Pacific region results in the realization of higher prices than are available in Canada or the United States, the netbacks per unit of production of natural gas (generally expressed in terms of thousands of cubic feet) shipped to Asia as LNG will be greater than on gas that is marketed to US buyers, as long as the positive price differential more than offsets the cost of liquefaction and the increased transportation cost involved in shipping LNG across the Pacific.

markets, such developments would certainly make sense to them from a strategic perspective. Most of the companies—certainly Korea Gas Corporation and Mitsubishi Corporation—have extensive experience in the LNG industry.

For strategic reasons, Canada needs to diversify its natural gas export markets. Instead of remaining almost entirely focused on sales of natural gas to markets in the United States, as in the past, Canada now needs to turn its attention to the emerging opportunities for LNG exports. As discussed later, there is a strong business case for such development. However, for a number of reasons, development of the required pipeline facilities and gas liquefaction facilities is proceeding at a slow pace.

Examining the obstacles to LNG export development and putting forward practical solutions that could make a real difference is the overriding objective of this publication. First, however, we examine the potential for LNG exports from British Columbia from the perspective of both the supply (resources and reserves) and the likelihood of Canadian gas producers securing a significant and permanent niche in the growing Asia-Pacific LNG market.

Production, reserves, and exports of natural gas in British Columbia

British Columbia is an important contributor to the Canadian supply of natural gas, accounting for about 20% (about 1 trillion cubic feet), of the country's total marketable gas production in 2010, second only to Alberta with 70% (National Energy Board, 2010).[1] There are abundant reserves of gas that can be produced via conventional means (i.e. by simply drilling a vertical well).[2] But, extensive opportunities are emerging for gas production from unconventional sources such as shale gas,[3] tight gas,[4] and coal-bed methane (gas embedded in coal seams).[5] Most of British Columbia's gas production comes from the northeastern region of the province (National Energy Board, 2011a).

---

1 The National Energy Board is an independent Canadian government agency established under the National Energy Board Act to regulate the international and interprovincial activities of oil, natural gas, and other energy pipelines, and of electric transmission facility operators.

2 Conventional natural gas production is carried out by drilling a well into a concentration of methane that is trapped in an underground geological structure or reservoir. In some cases, the gas that flows to the surface through the well bore is mixed with oil or natural gas liquids and must be separated. Conventional sources of natural gas are generally easier and less costly to produce than non-conventional sources such as shale gas, tight gas, and coal-bed methane, which are discussed below (National Energy Board, 2009). According to the National Energy Board, in some cases gas from low permeability reservoirs that is classified as conventional gas could be considered unconventional tight gas (National Energy Board, 2006).

3 Shale gas is natural gas produced from the fractures, pore spaces, and physical matrix of rock shale. They are the most commonly occurring type of sedimentary rock in northeast British Columbia (BC Ministry of Energy, Mines and Petroleum Resources).

4 Tight gas is natural gas located in very tight underground formations, trapped in unusually impermeable hard rock, or in a sandstone or limestone formation that is unusually impermeable and non-porous (NaturalGas.org, 2011). Tight gas reservoirs occur throughout much of northeastern British Columbia and in other parts of Canada, especially Alberta.

5 Coal-bed methane (CBM) is natural gas that is associated with coal deposits. This gas is contained in coal seams where it is absorbed or attached to the coal particles (BC Ministry of Environment, 2011).

According to the BC Oil and Gas Commission, British Columbia's estimated remaining marketable reserves[6] of conventional and non-conventional natural gas combined was 27.8 trillion cubic feet (Tcf) at the end of 2010[7] (BC Oil and Gas Commission, 2011) (table 1). In early 2011, production of British Columbia unconventional gas surpassed conventional gas production there for the first time. At the end of 2011, production from unconventional sources represented 60% of total daily gas production in the province (BC Oil and Gas Commission, 2011).

British Columbia is estimated to have an enormous quantity, 1,618 Tcf, of unconventional natural gas resources:[8] 100Tcf in the form of coalbed methane, 300 Tcf from tight gas, and 1,218 Tcf from shale gas (BC Ministry of Energy, Mines and Petroleum Resources, 2012) (table 2). As yet, only a relatively small portion of this resource has been classified as being economically recoverable and therefore considered to be part of the province's established "reserves." This is bound to change rapidly, however, as more knowledge of the extent and characteristics of the tight gas and shale gas in various formations becomes available.

The Montney tight-gas and Horn River and Liard Basin[9] shale-gas resources in northeast British Columbia are expected to play an increasingly important role, more than offsetting declines in conventional natural gas production[10] in the province. In a continued scenario of low gas prices—where natural gas prices do not exceed $3.8 per million cubic feet (Mcf)—British Columbia's conventional natural gas production is expected to decline

6 Remaining marketable reserves are initial reserves minus cumulative production. "Marketable" refers to gas volumes that are technically recoverable under current market conditions. The marketable volume is the gas volume that can be inserted into pipelines for sale (National Energy Board, 2011a).

7 In general, "marketable reserves" refers to natural gas resources in the ground that have been proven to exist as the result of exploratory drilling and other means and that are estimated to be feasible to produce under current economic conditions. Natural gas "resources" refers to natural gas in the ground that has been discovered or is expected to exist.

8 Unconventional natural gas refers to the gas found in non-typical settings or requiring non-typical extraction techniques, such as horizontal drilling and fracturing. This includes such resources as coal-bed methane, tight gas, shales, and gas hydrates (National Energy Board, 2011a).

9 The shale gas resource potential indicated in table 2 is based on information about the Montney and Horn River Basin plays. An announcement by Apache Corporation on June 14, 2012 indicates that the Liard Basin, which lies to the west of the Horn River Basin, also has enormous shale gas potential. Apache said that tests suggest that it has 48 Tcf of marketable gas within its Liard Basin properties, which make up a relatively small portion of the entire basin (Hamilton, 2012, June 15).

10 Conventional natural gas production includes solution and non-associated gas. Solution gas refers to dissolved gas in well-bore or reservoir fluids. Non-associated gas is found in reservoirs that do not contain significant quantities of crude oil.

Table 1: Marketable natural gas reserves in British Columbia, December 31, 2010

	Trillion cubic feet (Tcf)
Initial recoverable reserves (current estimate)	50.2
Cumulative production	22.4
Remaining reserves	27.8

Source: BC Oil and Gas Commission, 2011.

Table 2: Unconventional natural gas resources (Tcf) in British Columbia

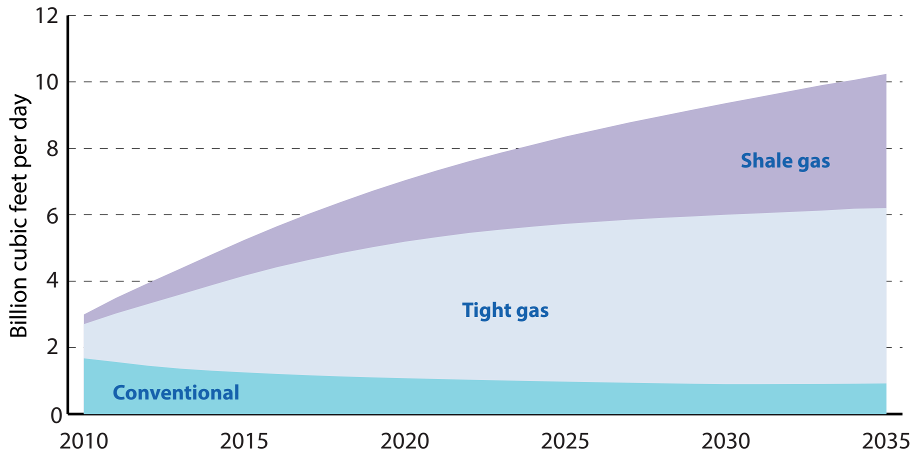
	Trillion cubic feet (Tcf)
Coalbed methane	100
Tight gas	300
Shale gas	1,218
Total	1,618

Source: BC Ministry of Energy, Mines and Petroleum Resources, 2012.

from 1.8 billion cubic feet per day (Bcf/day) in 2010 to 0.9 Bcf/day in 2035 (National Energy Board, 2011b). During the same time period, production from tight and shale gas formations is projected to grow from 1.3 Bcf/day in 2010 to 9.3 Bcf/day in 2035 (National Energy Board, 2011b). This would result in total BC natural gas production increasing by 7.2 Bcf/day, from 3.0 Bcf/day in 2010 to 10.2 Bcf/day in 2035 (figure 1).[11] British Columbia is

11 According to Environment Canada's data, an increase in gas production of this magnitude, along with the increase in processing and pipeline transportation activities would increase greenhouse gas emissions (GHG) by 28.5 megatonnes (MT) of CO_2 equivalent a year by 2035 (Environment Canada, 2011). That would be significant as it compares with actual GHG emissions from Canadian natural gas production of 62 MT CO_2-equivalent and in Canada as a whole of 692 MT of CO_2-equivalent in 2010 (Environment Canada, 2012). But, for the country as a whole the NEB is projecting natural gas production to increase by only 3.7 Bcfd from 2010 to 2035 because of declining output from maturing conventional reservoirs (National Energy Board, 2011b). Moreover, since that increase includes 1.2 Bcfd of Mackenzie Delta gas that the authors assume will not be developed before 2035, the actual increase in Canadian production from 2010 to 2035 may only be about 2.5 Bcfd. This suggests that GHGs from gas production and processing in Canada as a whole might not increase nearly so much as the projections for gas production in British Columbia alone suggest. However, a 2010 study by Marc Jaccard and Brad Griffin of Simon Fraser University indicates that gas from the Horn River Basin shale contains approximately 3.5 times as much CO_2 as conventional gas (Jaccard and Griffin, 2010). This means that production of 2 Bcfd of that gas in 2020 (which is closely similar to the National Energy Board's forecast) could contribute as much as 4.3 MT of additional CO_2-equivalent emissions per

Figure 1: Forecast natural gas production in British Columbia, 2010–2035



Source: National Energy Board, 2011b.

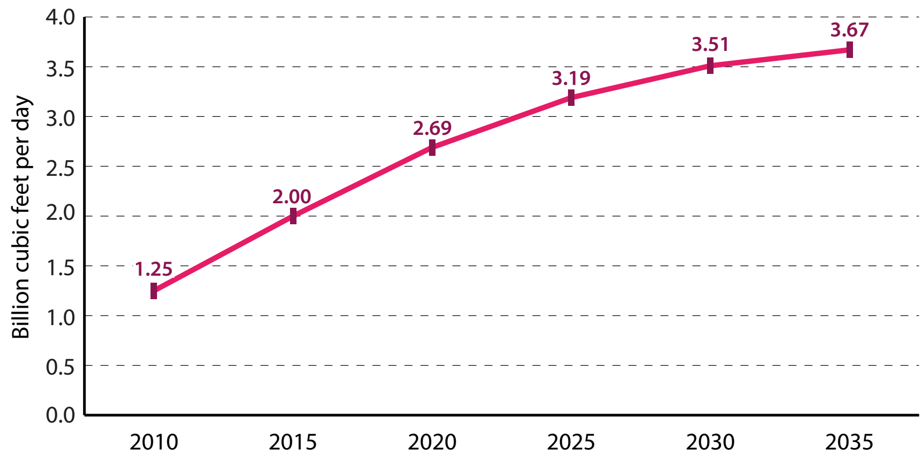
already self-sufficient in natural gas so the essential question is where will the increase in production from the shale and tight gas resources in northeast British Columbia be absorbed?

The National Energy Board anticipates that Canadian demand for natural gas will increase by 5.1 Bcf/day from 2010 to 2035, a compound annual growth rate of 2%. Most of the increase is related to growing gas demand for oil sands operations (National Energy Board, 2011b). Figure 2 illustrates the anticipated growth of gas demand to meet the thermal and electrical energy needs of increased bitumen production and upgrading activities arising from continued development of Alberta's oil sands. According to the National Energy Board, requirements for natural gas to support oil sands operations are expected to reach 3.7 Bcf/day by 2035 compared with only 1.25 Bcf/day in 2010, a compound annual growth rate of 4.4% (National Energy Board, 2011b).

The National Energy Board's most recent projection of total natural gas production in Alberta from all sources points to a decrease of 3.6 Bcf/day, from 10.5 Bcf/day in 2010 to 6.9 Bcf/day in 2035 (National Energy Board, 2011b). The increase in gas required for oil sands operations and declining gas production in Alberta suggest that oil sands operations will likely absorb some production from the anticipated development of tight and shale gas

year if the "extra" CO_2 is simply vented according to current practice. Further growth in production of Horn River Basin shale gas (the NEB is assuming that it will reach 4 Bcfd in 2035) would add even more to GHG emissions. Growth in production of natural gas in British Columbia, especially from the Horn River Basin shales, therefore appears to pose a challenge to the province's commitment to reduce GHG emissions. These could be controlled through capture and processing requirements but that would add to the cost and potentially make development of the sort examined in this study less attractive.

Figure 2: Natural gas purchased for oil sands operations, 2010–2035



Source: National Energy Board, 2011b.

resources in British Columbia. However, the decline in Alberta's conventional gas production is expected to be partially offset by the targeting of tight gas zones in the western Alberta Deep Basin, which are economically attractive because of the presence, with the gas, of marketable natural gas liquids such as pentanes plus and butane, already existing infrastructure, and changes to the royalty regime (National Energy Board, 2011a). Further, competition for British Columbia's gas is likely to arise from the development of shale gas resources that extend into Alberta from northeastern British Columbia.[12]

Clearly, the feasibility of rapid development of British Columbia's shale gas resource hinges on the potential to increase Canadian gas exports to the United States and to develop new markets overseas. Exports of natural gas from British Columbia flow into the US Pacific Northwest mainly through the gas transmission system of Spectra Energy (operating as Westcoast Energy) that connects with the Williams Companies Inc.'s Northwest Pipeline at Sumas, Washington. Figure 3 illustrates gas export volumes at Sumas in recent years.

Some natural gas from British Columbia also enters TransCanada Corporation's Alberta System at Gordondale at the BC-Alberta border. Once on the Alberta System, gas can be piped to markets in eastern Canada and the United States via several routes. For example, the Foothills Pipeline, which is connected to the Alberta System, connects with the TransCanada's Gas

12 In its most recent long-term forecast of natural gas supply, the National Energy Board did not attempt to estimate the extent of Alberta's likely shale gas resources and the rate at which they might be developed and produced. The explanation provided for this was that insufficient information was available.

Figure 3: Exports of natural gas from British Columbia to the United States through the Westcoast Transmission System, 2007–2010

Source: BC Ministry of Petroleum, Energy and Mines, 2010.

Transmission Northwest (GTN) pipeline at Kingsgate at the border between British Columbia and Idaho, and GTN connects with Pacific Gas and Electric Company's California Gas Transmission System at Stanfield, Oregon. Gas from British Columbia and Alberta also flows to the US Midwest via the Alliance Pipeline, which originates in northeast British Columbia.

In anticipation of increasing production from British Columbia's shale and tight gas resources, Spectra Energy is in the process of extending the northern part of its Westcoast Energy Transmission system to accommodate deliveries from supplying producers. Also, TransCanada is constructing pipelines such as the Groundbirch Pipeline to connect the Montney, Horn River, and Cordova basins to the Alberta System. Such expansions and extensions will ensure that increased gas production will be able to reach market regions in Canada and the United States through the integrated transmission grid that traverses the continent. But to what extent and on what terms (price) will the traditional export markets be capable of, and willing to, absorb the gas?

Development of the immense shale and tight gas resources in northeast British Columbia and the pipeline gathering system in the region might be expected to lead to considerable increases in export volumes on the Westcoast system and other pipeline routes. However, growth of exports to the United States is likely to be very modest, at best, because of competition from growing gas production in the US Rocky Mountain region and the continuing development of shale gas plays in Texas, Arkansas, Louisiana, Michigan, Pennsylvania, and other states. Further, burgeoning gas supplies in the United States are likely to keep prices at the key US market hubs—the key determinants of Canadian netbacks—depressed for some time.

In its most recent long-term energy forecast, *Annual Energy Outlook 2012*, the US Energy Information Administration paints a rather gloomy picture of the prospects for gas imports from Canada during the period to 2035. The main reason for this is the projected growth of US unconventional gas production (tight, shale, and coal-bed methane) from 12.7 Tcf (34.9 Bcf/day) in 2010 to 21.4 Tcf (58.6 Bcf/day) in 2035.[13] The shale gas share of US gas production is anticipated to reach 49% in 2035 compared with only 23.2% as recently as 2010 (US EIA, 2012a). Only a few years ago—that is, prior to the production of gas from shale formations becoming feasible as the result of advanced technologies, especially horizontal drilling and multi-stage hydraulic fracturing—the United States was expected to become heavily dependent on imported LNG in 20 to 30 years. Now, US imports of LNG are not expected to increase and imports of gas via pipeline are anticipated to decline (figure 4).[14]

Clearly, development of British Columbia's very large shale gas resource will be severely constrained without access to offshore LNG markets. Development of the Kitimat LNG project[15] and the BC LNG Export Co-operative[16] project will be a start and will make a real difference, providing conduits for at least 560 billion cubic feet of gas per year. But the size of British Columbia's natural gas resources would permit much more rapid growth of production than this.

For discussion of the potential economic impacts from LNG exports (p. 20 ff.), we developed a hypothetical BC LNG export scenario to 2035 that includes not only the two projects mentioned above, but three additional projects with respect to which, in one case, an application has already been filed with the National Energy Board. According to this scenario, LNG exports could reach 7.1 Bcf/day by 2032.

---

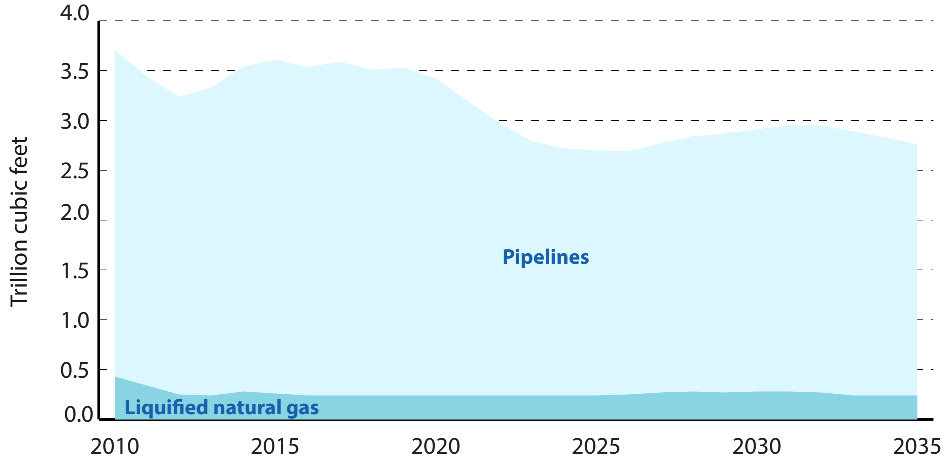
13 The EIA assumes that the average price of natural gas (Henry Hub spot price) will fall from US$4.39 per MMBtu (million British thermal units) in 2010 to US$4.27 per MMBtu in 2015, but reach US$5.75 per MMBtu in 2025 and US$7.23 per MMBtu in 2035 (US EIA, 2012a).

14 According to a recent US Government study, some of the gas that is imported from Canada will be necessary to help meet US LNG export requirements (US EIA, 2012b).

15 The Kitimat LNG project would involve construction of an LNG export terminal near the Port of Kitimat on the northern Pacific coast of British Columbia. The terminal would have an initial capacity of 0.7 Bcfd of natural gas and the ability to add an additional 0.7 Bcfd via expansion. The proponents of the Kitimat LNG project are Apache Canada, EOG Resources Canada, and EnCana Corporation. The NEB granted Kitimat LNG an export license in October 2011.

16 The BC LNG Export Co-operative is a 50-50 partnership between LNG Partners LLC (based in Houston, Texas) and the Haisla Nation Douglas Channel LNG Limited Partnership. The BC LNG Export Co-operative applied to the National Energy Board for a license to export LNG from a gas liquefaction plant in Kitimat, British Columbia, with an initial capacity of 250 million cubic feet per day (0.25 Bcfd). The Board approved the application in February 2012.

Figure 4: Imports of natural gas by the United States, 2010–2035

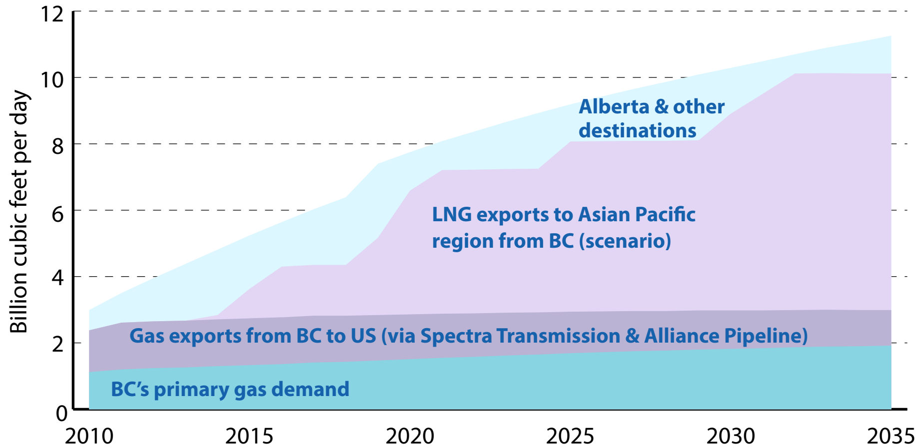


Source: US Energy Information Administration, 2012a.

Figure 5 illustrates how British Columbia's production of natural gas could be distributed between domestic demand on the one hand and exports to markets in the United States, Alberta, other Canadian destinations, and Asia (as LNG), on the other. The projection of British Columbia's gas requirements is from the National Energy Board's most recent long-term projection (National Energy Board, 2011b). Our forecast of British Columbia's gas exports to the United States assumes that shipments of BC gas to US markets will remain at their estimated 2011 volume until 2018, when they begin to decline by 1.5% per year in the face of increasing competition from US supplies (BC Ministry of Energy, Petroleum and Mines, 2011b).[17] The projected LNG exports to the Asia-Pacific region in figure 5 are consistent with an assumed LNG export scenario that is described later in this report as the basis for estimation of the gross economic benefits that could flow from development of British Columbia's LNG export facilities. The shale and tight gas resource base in British Columbia could support greater and more rapid development of LNG exports than implied by the National Energy Board's forecast of British Columbia gas production illustrated in figure 1 if the required infrastructure—including pipeline facilities to transport the gas to the coast, electric generation capacity, gas liquefaction facilities, and marine terminals—is put in place. For this reason, the gas production forecast for British Columbia shown in figure 5 assumes that, commencing in 2019, output will be 10% greater than in the National Energy Board's reference case.

17 Here we are referring to natural gas production exported from British Columbia to the United States via Spectra Transmission and the Alliance Pipeline. The decline in exports is predicated on the assumption that Canadian gas will become increasingly difficult to market in the United States because of a burgeoning supply of gas there.

Figure 5: Projected allocation of British Columbia's natural gas production, 2010–2035



Source: BC Ministry of Petroleum, Energy and Mines, 2011b; National Energy Board, 2011b; authors' estimates.

Prospects for natural gas demand in the Asia-Pacific region

The use of liquid natural gas (LNG) has been growing rapidly in the Asia-Pacific market region, mainly as a needed energy source for electric generation but also for distribution to residential, commercial, and industrial consumers. The growth in LNG requirements has been strongest in Japan, Korea, and Taiwan, which, together, accounted for 86% of Asia-Pacific LNG trade in 2009. China and India, which are also becoming important LNG markets, represented 13% of LNG trade in the region in 2009 but, together, are expected to account for a greater share in the future as a result of continued economic development (Poten and Partners, 2010).

New LNG supplies will be needed to fill the gap between supply and demand in the region that is expected as the result of the inability of some suppliers in Malaysia, Indonesia, and Brunei to renew contracts because of dwindling supplies, increased domestic gas consumption, or both (Poten and Partners, 2010). The shrinkage of available supplies from other countries in the region will be exacerbated by the anticipated growth in demand summarized below (see figure 6, p. 15).

Japan

Japan is dependent on LNG imports to meet nearly all of its natural gas requirements. According to the United States Energy Information Administration (US EIA), Japanese natural gas consumption is projected to reach to 11 Bcf/day in 2035, an increase of 10% compared with 2010, implying a compound annual growth rate of only 0.4% (US EIA, 2011a). However, that forecast was undertaken in mid-2011 before the Japanese government had determined to what extent to alter the country's reliance on nuclear power as a result of the 2011 tsunami disaster. A decision in that regard is anticipated this year. Assuming that Japan will decide to decommission some of its nuclear plants, there is potential for growth in gas demand more rapid than that projected by the US EIA. In this regard, a recent forecast by PFC Energy in support of LNG Canada's project application to the National Energy Board suggests that reduced reliance on nuclear power will cause gas demand in Japan to increase by 1.4% a year to 2030, but only at a "minimal"

rate thereafter (PFC Energy, 2012). In that case, Japanese gas requirements would be 2.8 Bcf/day greater in 2035 than the US EIA's projection.

South Korea

South Korea produces very little natural gas (only 0.05 Bcf/day in 2010) and, like Japan, is therefore virtually entirely dependent on LNG imports (British Petroleum, 2011). The most recent forecast by the US EIA projects South Korean consumption of natural gas to grow from 3.6 Bcf/day in 2010 to 5.2 Bcf/day in 2035 (an implied 1.5% compound annual growth rate), led by strong growth in demand by the electric power sector (US EIA, 2011a).[1] In part, this is because the share of natural gas consumption used for electricity generation is anticipated to increase from 39% in 2010 to 48%. As deregulation in the electric power sector moves forward, South Korea's electricity producers will be able to contract directly with global LNG suppliers, stimulating further growth in natural gas demand for the electric power sector.

PFC Energy is forecasting South Korean gas demand to grow strongly for essentially the same reasons but their projection is a bit more robust. They are calling for gas demand to grow by 2.3% per year to 2030 and by about 1% annually thereafter. PFC Energy's projection for South Korean gas demand for 2035 is about 0.7 Bcf/day greater than the US EIA's forecast (PFC Energy, 2012).

India and China

In India and China, natural gas has been a relatively minor component of the overall energy mix, accounting for only 10% in India and 3% in China of total energy consumption in 2010 (US EIA, 2011a). While natural gas consumption in India is projected to increase slightly as a share of the country's overall energy requirements (from 10% to 10.4%), in China natural gas as a share of energy consumption is expected to double (from 3% to 6%) by 2035, compared with 2010 (US EIA, 2011a). LNG is clearly becoming an important energy source for both countries.

Indian natural gas consumption is projected to grow from 6.6 Bcf/day in 2010 to 14 Bcf/day in 2035, mainly because of rapid industrialization (US EIA, 2011a). Domestic production of natural gas, which has been the major source of gas supply in the country, has not been growing sufficiently to meet rising demand. Consequently, India is turning to LNG imports. A number of LNG terminals have been constructed in India in recent years. Petronet LNG Limited of India set up the country's first LNG receiving and regasification terminal at Dahej, Gujarat, and is in the process of building another terminal at Kochi, Kerala. In 2011, the state of Gujarat, where two of India's

1 The EIA's most recent long-term projection of Korean gas demand was contained in its 2011 International Energy Outlook (US EIA, 2011a).

four LNG import facilities are located, proposed to increase its annual LNG import capacity to 1.2 trillion cubic feet (Tcf) (3.3 Bcf/day) from 0.5 Tcf (1.4 Bcf/day) (Shah, 2011, May 24).

Chinese consumption of natural gas is projected to grow at a compound annual growth rate of 5.1% from 2010 to 2035—the second highest growth rate worldwide after Brazil—to reach 31.5 Bcf/day compared with 9 Bcf/day in 2010 (US EIA, 2011a). That projection is conservative compared with the 9% annual growth rate in Chinese gas consumption assumed by PFC Energy, which exceeds the EIA's forecast by 24 Bcf/day by 2035 (PFC Energy, 2012). In both cases, much of the growth in demand comes from requirements for electric generation fuel in response to continued growth in the demand for electricity as the economy expands.

China will able to meet some of its gas requirements from domestic gas production, which is also growing rapidly. However, uncertainty surrounding the extent to which the Chinese will succeed in ramping up gas production makes it more difficult than it otherwise would be to project Chinese LNG imports. According to Poten and Partners, the growth in gas demand will boost Chinese LNG import requirements to 8.4 Bcf/day by 2030 (Poten and Partners, 2010). On the other hand, PFC Energy forecasts that the need for LNG will increase much more rapidly, especially after 2025 when gas production is assumed to begin to decline. However, the firm notes that there is considerable potential for greater gas production, which could change the outlook for LNG imports considerably. In either case, it appears that China is likely to become increasingly dependent on LNG imports for some time to come. Further, as PFC Energy notes "since the appetite for gas in China is very high and gas penetration levels are still very low, the market would be able to absorb additional gas supply from domestic production without lessening the demand for LNG imports" (PFC Energy, 2012: 16).

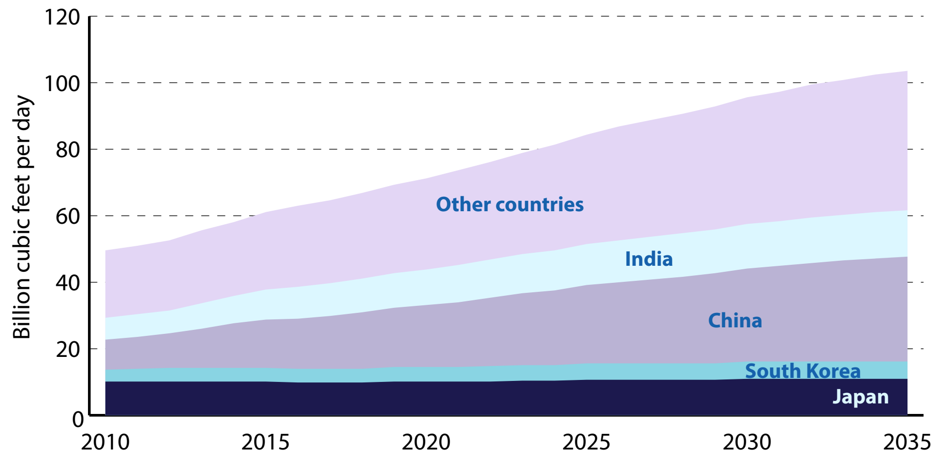
Other countries in the Asia-Pacific region

In the non-OECD Asian countries other than China and India,[2] natural gas is already a large component of the energy mix. According to the US EIA, their annual natural gas consumption is projected to increase by 21.6 Bcf/day from 2010 to 2035 (US EIA, 2011a). Several countries in the region such as Indonesia, Thailand, and Singapore are building LNG receiving terminals and will join the league of LNG importers in the next few years. Indonesia, in response to strong growth in domestic gas requirements in recent years, has established policies to give priority to natural gas consumption instead of exports.

Like Japan and South Korea, Taiwan depends on imported LNG to meet virtually all of its natural gas demand. Natural gas consumption, over 80% of

2 Non-OECD refers to countries that are not members of the Organization of Economic Co-operation and Development. Japan, South Korea, Australia, and New Zealand are the only OECD members in the Asia-Pacific region. Other countries are classified as non-OECD Asia.

Figure 6: Forecast demand for natural gas in the Asia-Pacific region, 2010–2035



Source: US Energy Information Administration, 2011a.

which is for power generation, increased at a compound annual growth rate of 7.6% in that country from 2000 to 2010 (British Petroleum, 2011). About 1.6 Bcf/day of LNG were consumed in Taiwan during 2011. The country's LNG requirements are projected to double by 2030 as the result of an assumed 3.5% annual growth rate in gas consumption, and to increase by about 1.1% per year from then to 2035 as growth of demand for gas by the power sector slows (PFC Energy, 2012). Taiwan's LNG requirements are projected reach 3.3 Bcf/day in 2035 compared with approximately 1.4 Bcf/day in 2010.

Overall demand

As illustrated by figure 6, natural gas consumption in Japan, South Korea, China, India, and the rest of the non-OECD countries in Asia combined (including Taiwan) is projected by the US EIA to increase from 50 Bcf/day in 2010 to 104 Bcf/day in 2035 (US EIA, 2011a). Because, as indicated earlier, growth of demand for gas in Japan, South Korea, and China may be more rapid than the US EIA is predicting, the estimated increase in total gas demand in the region that is depicted in the figure may be conservative.

To help meet the increase in gas demand in these countries, Poten and Partners are projecting that LNG imports will grow at a compound annual rate of 2.7% from 2014 to 2035. They also predict that the projected shortfall in the supply of LNG will increase from around 400 billion cubic feet per year (1.1 Bcf/day) in 2015 to 6.3 Tcf per year (17.3 Bcf/day) in 2035 (Poten and Partners, 2010).[3] PFC Energy is more bullish, suggesting that 6.6 Bcf/day of additional LNG import capacity could be needed by Japan, Korea, and China alone as early as 2020, and 37.5 Bcf/day by 2035 (PFC Energy, 2012).

3 The "supply/demand gap" is the difference between projected LNG import supplies based on existing import facilities and known and committed new projects, and the LNG volumes that are anticipated to be required in light of current demand projections.

The opportunity cost of confining gas exports to US markets

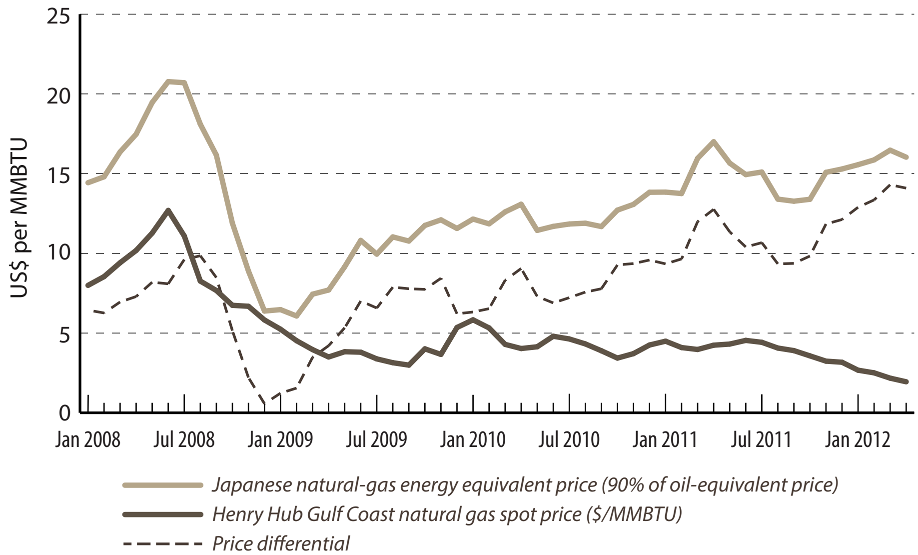
Some producers of British Columbian natural gas such as EnCana, Apache Canada, EOG Canada Ltd., Shell and Progress Energy are planning to avoid the opportunity cost that they would face if they sought to market all of their production in Canada and the United States. Instead of continuing to focus only on US and Canadian markets, where gas supplies have become glutted by increasing tight and shale gas production, and gas prices are expected to remain low for the foreseeable future, they are seeking higher prices and stable, long-term LNG sales agreements with buyers in Asia-Pacific countries.

Given the price risk, and the high cost of developing LNG liquefaction and terminal facilities, developers of LNG export projects generally prefer long-term contracts. Fortunately, companies in the Asia-Pacific region that are operating and developing gas-fired power generation facilities and natural gas distribution systems desire contractual arrangements that provide for stable, dependable sources of supply and, therefore, would probably be comfortable dealing with gas producers in a politically stable and secure country such as Canada.

The price of imported LNG in the Asia-Pacific is frequently indexed to the Japan Customs Cleared (JCC) price for Japanese crude oil imports as compiled by the Japanese government. The JCC price itself closely follows the price of Brent (North Sea) crude oil but with a two-month lag because of the time required to compile the data. LNG prices in the various countries tend to move more or less together since they are generally a function of the cost of crude oil but they do diverge according to differences in the composition of supply. Because LNG prices in Japan and also throughout the Asia-Pacific region are approximately 90% of the price of oil on an equivalent heating-value basis, they have been, and continue to be, considerably higher than gas prices in the United States (figure 7) (Poten and Partners, 2010).

LNG prices are difficult to project with accuracy for several reasons. First, it is not clear when and where new LNG production positioned to supply the Asia-Pacific market will come on stream and what the price terms of new contracts will be. Second, in countries where gas demand is particularly strong relative to available supply and some long-term LNG supply contracts

Figure 7: Japanese LNG and US Gas Prices, January 2008–April 2012



Source: US Energy Information Administration, 2011b, 2011c.

are not being renewed as a consequence of supply constraints in the source country (as with supplies from Indonesia, which is now giving priority to local requirements), upward pressures are likely to emerge. Further, the oil price mechanisms being used to determine LNG prices guarantee that there will be some fluctuation and volatility in LNG prices because oil prices are subject to market forces and, therefore, inherently difficult to predict.

Strong growth in the demand for natural gas in the Asia-Pacific countries will help to sustain LNG prices. As LNG supplies to Asia from North America, Australia, and other parts of the globe increase, differentials between LNG prices in Asia and natural gas prices in Canada and the United States are likely to come under some downward pressure. In fact, with favourable terms of trade and competitive markets one would normally expect to see the disequilibria between natural gas prices in North America and Asia shrink in time as the result of trade and consumption adjustments. However, it is anticipated that continued robust growth of LNG demand in the emerging Asian countries will continue to provide a premium for investors in new LNG export facilities during at least the next 10 to 20 years.

Canadian LNG exports would allow gas producers to take advantage of price differentials in natural gas pricing between North America and the Asia-Pacific region. Recent data show Japanese customers paying over $US15.45 per thousand cubic feet (Mcf) for liquefied natural gas, while suppliers in western Canada are only receiving the equivalent of $US3.38/Mcf. However, Canadian producers would not realize the full price differential of $12.07/Mcf (Tertzakian, 2011, October 17). Among other factors, the cost of transporting gas to the west coast (about 70 cents/Mcf), converting the gas to

LNG at a facility such as that proposed for Kitimat (about $3.00/Mcf), and transporting it to the Asia-Pacific region (in the case of Japan, 85 cents/Mcf) would have to be deducted (Kitimat KNG, 2010). By way of example, for the 10-year period from 2014 to 2024 the proponents of the Kitimat LNG project have suggested that, overall, an average incremental netback (after deducting all costs) of $3.85/Mcf could be achieved on Canadian LNG exports to Japan compared to gas exports to the United States (Kitimat LNG, 2010). The underlying calculations are provided in table 3.

This is not to say that there is no price risk in relation to the development of LNG export facilities. For example, it is possible that a significant spot market for LNG supplies could develop in the Asia-Pacific region as its dependency on imported LNG grows. In this regard, though, because importers of gas supplies for power generation and for distribution to urban centres as a thermal energy source require a high level of certainty about both supply and cost, it is likely that most LNG imports will likely continue to be subject to contractual arrangements negotiated between sellers and buyers for defined periods. Another possible problem is that, in their haste to secure positions in the attractive Asian LNG market before the current window of opportunity closes, developers of large-volume facilities may be tempted to undercut, and thereby squeeze out, competitors. In so doing, they may negotiate novel pricing arrangements. For example, a US LNG export company has reportedly agreed to a pricing formula based on the US price of natural gas. If this practice were to become widespread, it which could make it difficult for other developers (such as Kitimat LNG Inc.) to secure the oil-based pricing upon which their project plans are based (Healing, 2012, October 2).

Some may argue that Canadian LNG exports would improve the price (and therefore, netbacks) available to Canadian producers selling gas to US and Canadian markets because the shipments to overseas destinations would reduce the volume of gas that is available to meet Canadian and US demand. If this were true then, through time, the LNG exports would reduce the opportunity cost of not shipping gas overseas, making exports to the Asia-Pacific region somewhat less attractive to the producers. The problem with this argument is that there is now so much tight and shale gas potential in Canada and the United States that an increase in price would almost certainly trigger further development.[1] Consequently, any short-term price gains and netback improvements would likely soon disappear.

1 One indication of the developing excess gas supply in the United States is the growing list of proposals for US LNG exports.

Table 3: Net spread between Japanese and North American prices for natural gas ($/million cubic feet)

LNG Price in Japan excluding security premium	14.91
Add: supply security premium [1]	+0.50
LNG in northeast Asia including security premium	15.41
Less: shipping cost from Kitimat to Tokyo	−0.85
LNG free-on-board at Kitimat	14.56
Less: liquefaction cost	−3.00
Less: transport on PTP from Summit Lake to Kitimat [2]	−0.60
Less: transport from Station 2 to Summit Lake [3]	−0.08
A. LNG Netback at Station 2	10.88
Natural Gas Henry Hub Price	7.99
Less: Station 2 basis (i.e., transportation cost from Henry Hub to Station 2	−0.96
B. Natural Gas Price at Station 2	7.03
Incremental Netback after Costs (A – B) *[4]*	3.85

Note 1: Supply security premium is the premium that LNG suppliers are able to secure by guaranteeing on-time delivery to destinations such as Japan.

Note 2: PTP refers to the proposed Pacific Trail Pipeline that would transport natural gas from Summit Lake on the Spectra Energy Transmission System to the Kitimat LNG export facility.

Note 3: Station 2 is the pumping station on the Spectra System north of Summit Lake at which the Zone 3 tariff becomes applicable.

Note 4: This illustrative incremental netback put forward by the proponents of the Kitimat LNG would appear to be conservative given that the surge in shale gas production is likely to suppress the price of gas at the Henry Hub market centre well below the indicated price for some time to come.

Source: Kitimat LNG, 2010.

Gross economic impacts from access to Asia-Pacific LNG markets

In this section, we present an assumed development scenario with respect to BC LNG exports and then focus on the ensuing gross economic impacts that one could reasonably expect to ensue. The estimated impacts are derived from conventional input-analysis which, by definition, fails to evaluate the offsets that occur when workers leave employment in one region or industry to respond to opportunities in another and the economic consequences if opening new transportation corridors were to reduce flows and activities along other paths. We are examining, therefore, the prospective gross, rather than net, economic benefits from British Columbian LNG exports.

1 An LNG export development scenario

In order to provide a high-level assessment of the potential gross economic impacts from exporting LNG from British Columbia to countries in the Asia-Pacific region, we developed a plausible hypothetical development scenario as a basis for the analysis. As shown in earlier sections, it appears that development of British Columbia's huge shale and tight gas resources would be very much constrained without access to new markets. We have assumed that the projects of Kitimat LNG Inc. and BC LNG Export Co-operative LLC, for which applications have been approved by the National Energy Board, will proceed within the next three years.[1] We have also assumed the construction of additional LNG liquefaction facilities and terminals during the period up to 2035, including the recently announced LNG Canada project proposed by Shell Canada and partners Korea Gas Corporation (KOGAS), Mitsubishi Corporporation, and Petro China Co. Ltd. (LNG Canada, 2012). Projects A and B were assumed as "placeholders" for projects such as Petronas Inc., and Imperial Oil Ltd. and that company's 70% owner, ExxonMobil Corp., were understood to be considering.[2]

1 Application for construction of natural gas pipelines to supply these terminals must still be filed and approved by the BC Oil and Gas Commission.

2 As noted earlier, the Asia-Pacific BC LNG export scenario presented here is compatible with the National Energy Board's November 2011 forecast of gas production In British Columbia. However, on June 28, 2012 Progress Energy Resources Corp. indicated that the

Our LNG export scenario for British Columbia is summarized in table 4. In this case, total LNG exports from British Columbian shipping terminals reach 7.1 Bcf/day by 2032. Whether that rate will be achieved will depend on a number of factors, including the extent to which the increase in natural gas requirements for oil sands bitumen production and upgrading is met by Alberta gas production[3] and how the relationship between Asian LNG prices and the price of natural gas in British Columba evolves.

Our LNG development scenario assumes that BC LNG Export Co-operative LLC. will begin exports at the rate of 0.13 Bcf/day (46 Bcf per year)[4] in 2014, operating at 50% of its total capacity. Exports from that facility are projected to reach 0.25 Bcf/day (91 Bcf per year) in the following year when the facility is assumed to be operating at full capacity.

The Kitimat LNG facility is assumed to commence operations in 2015, exporting 0.64 Bcf/day (234 Bcf per year) that year, and to reach full capacity and export 1.28 Bcf/day (467 Bcf per year) in 2016 and in subsequent years. As per the application that LNG Canada filed with the National Energy Board on July 27, 2012, that facility is assumed to begin operations in 2019 with the first LNG "train" (natural gas liquefaction facility) producing at the rate of 0.8 Bcf/day, increasing to 1.6 Bcf/day the following year when the second train commences operations (National Energy Board, 2012b). Additional 0.8 Bcf/day trains are assumed to be added at that facility in 2025 and 2030, respectively.

With British Coumbia's production of natural gas assumed to reach 11.26 Bcf/day (10% greater than the NEB's forecast) in 2035, more LNG facilities are likely to be proposed and approved. For this reason we assumed that LNG export facilities for the two "placeholder" projects, A and B, will be built near Kitimat, British Columbia in addition to those described above. Project A is assumed to begin operation in 2020, initially exporting 0.6 Bcf/day (219 Bcf

company is being purchased by Petronas Inc. of Malaysia, which expects shipments from the BC LNG export project that it is planning to commence by 2018 (Progress Energy, 2012). Development of that and other projects that are currently under discussion could result in greater development than we assumed and, accordingly, increase the estimated economic impacts discussed in this section.

3 As figure 5 on page 11 indicates, the volume of BC gas production assumed to underpin the LNG export scenario presented in this report allows for some BC gas to flow to Canadian and US gas-market hubs. Presumably, BC gas could help to meet the increase in gas demand that will be needed to support the growth of oil sands bitumen production and processing in Alberta. But most of the incremental gas supplies required by the oil sands are assumed to come from further development of Alberta tight and shale gas production.

4 Actual deliveries of LNG will occur on a periodic basis while ships are being loaded. LNG exports will occur periodically as fully loaded vessels leave Canadian waters. Initially, at least, such shipments will not occur on a daily basis.

Table 4: LNG export scenario (Bcf/day)

	BC LNG Export Co-op. (all phases)	Kitimat LNG	LNG Canada	Project A	Project B	Total LNG Exports
2014	0.13	—	—	—	—	0.13
2015	0.25	0.64	—	—	—	0.89
2016	0.25	1.28	—	—	—	1.53
2019	0.25	1.28	0.80	—	—	2.33
2020	0.25	1.28	1.60	0.60	—	3.73
2021	0.25	1.28	1.60	1.20	—	4.33
2025	0.25	1.28	2.40	1.20	—	5.13
2030	0.25	1.28	3.20	1.20	—	5.93
2031	0.25	1.28	3.20	1.20	0.60	6.53
2032	0.25	1.28	3.20	1.20	1.20	7.13
2035	0.25	1.28	3.20	1.20	1.20	7.13

Sources: National Energy Board, 2012 (re BC LNG Export Co-operative); National Energy Board, 2011d (re Kitimat LNG); Shell, 2012 (re LNG Canada); authors' assumptions.

per year) of LNG, and to reach its full capacity of 1.2 Bcf/day (438 Bcf per year) in 2021. Project B is assumed to begin exporting LNG at the rate of 0.6 Bcf/day in 2031 and to reach full capacity in 2032.[5]

2 Assumed pipeline construction and expansions

Sufficient pipeline capacity will be required to transport natural gas to the LNG export terminals. The new or expanded pipelines that are addressed in our development scenario are illustrated by the map (p. 23). The proposed Pacific Trail Pipeline (PTP)[6] will connect Spectra Energy's (Westcoast) T-South system at Summit Lake, British Columbia to the Kitimat LNG terminal and, possibly, to the BC LNG Export Co-operative terminal. Moreover, the Pacific Northern Gas (PNG) pipeline, which also connects with the Spectra system at Summit Lake, is expected to ship gas to the BC LNG Export Co-operative's facility in Kitimat via the branch that runs from Terrace, British Columbia.

5 The size of British Columbia's natural gas resource would allow even greater, more rapid development of LNG export capacity than we have assumed.

6 The Pacific Trail Pipeline (PTP) is a proposed 1.4 Bcfd pipeline that would run approximately 463 kilometres from the Kitimat LNG export terminal to the Spectra Energy (operating as Westcoast Energy) gas-transmission system at Summit Lake in east central British Columbia, which ties into the North American natural gas transmission grid. PTP would be owned by PTP Limited Partnership, a consortium made up of Apache Canada Ltd., EOG Resources Canada Inc., EnCana Corporation, and a group of First Nations.

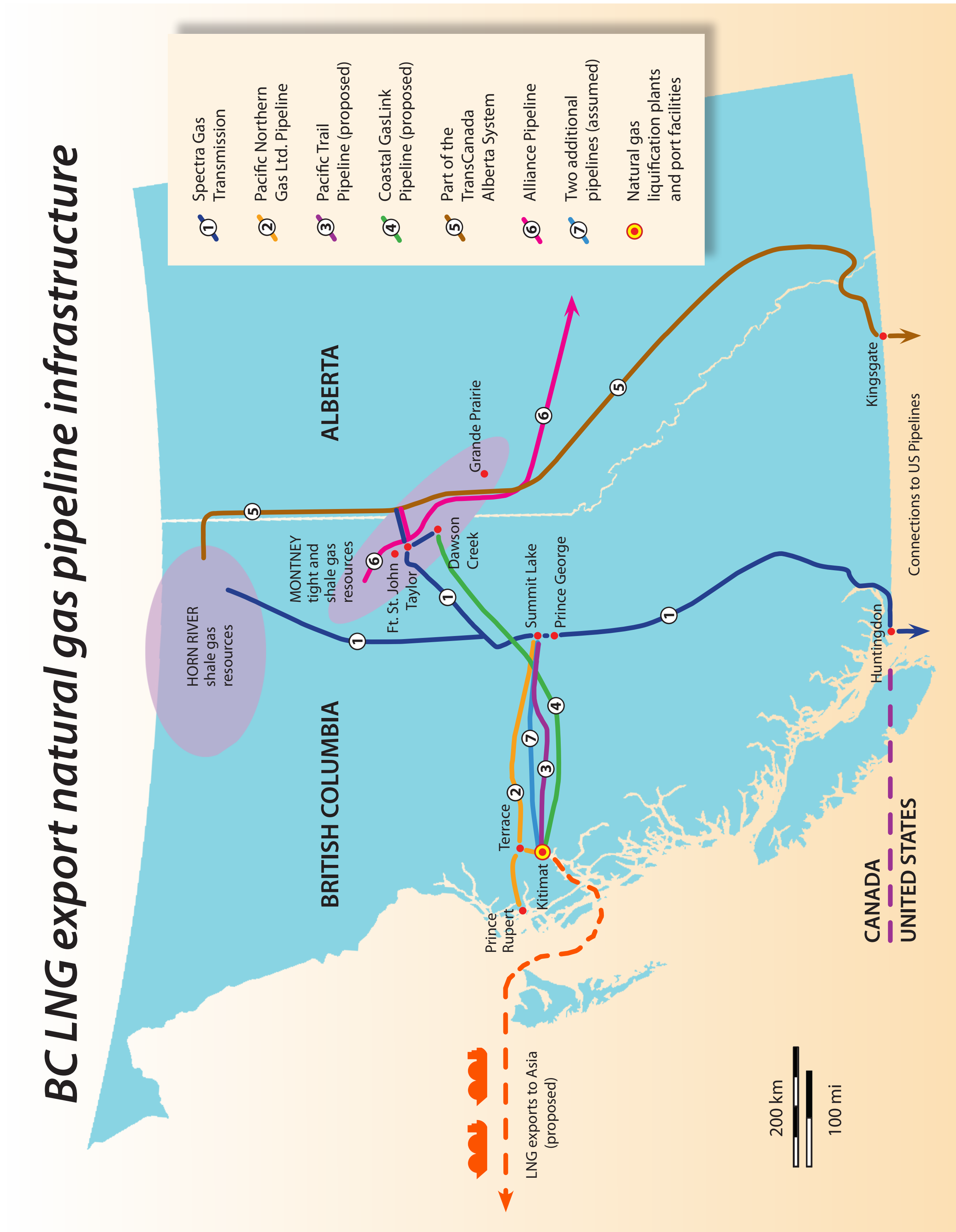

BC LNG export natural gas pipeline infrastructure
1 Spectra Gas Transmission
2 Pacific Northern Gas Ltd. Pipeline
3 Pacific Trail Pipeline (proposed)
4 Coastal GasLink Pipeline (proposed)
5 Part of the TransCanada Alberta System
6 Alliance Pipeline
7 Two additional pipelines (assumed)
Natural gas liquification plants and port facilities
ALBERTA
BRITISH COLUMBIA
HORN RIVER shale gas resources
MONTNEY tight and shale gas resources
Grande Prairie
Dawson Creek
Ft. St. John
Taylor
Summit Lake
Prince George
Terrace
Kitimat
Prince Rupert
Kingsgate
Huntingdon
Connections to US Pipelines
CANADA
UNITED STATES
LNG exports to Asia (proposed)
200 km
100 mi

Table 5: Scenario for construction of natural gas pipelines (capacity, Bcf/day)

	Pacific Northern Gas (Terrace to Kitimat)	Pacific Trail	Coastal GasLink	New pipeline A	New pipeline B	Total capacity
2010	0.09	—	—	—	—	0.09
2013	0.18	—	—	—	—	0.18
2015	0.27	1.40	—	—	—	1.67
2019	0.27	1.40	1.74	—	—	3.41
2020	0.27	1.40	1.74	1.31	—	4.72
2025	0.27	1.40	2.60	1.31	—	5.58
2030	0.27	1.40	3.40	1.31	—	6.38
2031	0.27	1.40	3.40	1.31	1.31	7.69
2035	0.27	1.40	3.40	1.31	1.31	7.69

Source: authors' assumptions.

The terminal proponents and Spectra Energy are aware of the need for additional pipeline capacity on Spectra's British Columbian transmission system from the developing shale and tight gas fields, including gathering system extensions and upgrades. We have assumed that any additions to the present capacity of the Spectra system that are needed will be approved by the NEB and put in place as required (see National Energy Board, 2011c). Our assumed scenario for construction of pipelines is summarized in table 5.

As stated in the NEB's reason for decision in which the Kitimat LNG project proponents' application for an export license was approved, it is anticipated that the capacity of the Pacific Trail Pipeline will be 1.4 Bcf/day (Natural Energy Board, 2011d). We assumed that that pipeline will be fully operative by 2015 in order to support shipments to the Kitimat LNG facility.

In addition, we assumed that Pacific Northern Gas Limited's current capacity of 0.09 Bcf/day (from Terrace to Kitimat) will be expanded to 0.18 Bcf/day in 2013 and to 0.27 Bcf/day in 2015 to support gas shipments to the BC LNG export facility. We also assumed the two other new pipelines, each with a capacity of 1.31 Bcf/day, would be built and commence service in 2020 and 2031, respectively, in order to support the Project A and Project B LNG export facilities.

TransCanada Corporation recently announced that it had been selected by Shell and that company's partners to design, build, own, and operate the proposed "Coastal GasLink" project (TransCanada, 2012). We have assumed that this pipeline will have an initial capacity of 1.74 Bcf/day and begin operating in 2019.[7] Also, in keeping with our assumptions about the subsequent

7 The capacity of the proposed Coastal GasLink pipeline has not yet been determined. In its announcement of June 5, 2012 TransCanada indicated that the capacity would be "in excess of 1.7 billion cubic feet of gas per day" (TransCanada, 2012).

expansion of the LNG Canada facility, we assumed that the Coastal GasLink pipeline's capacity will be expanded to 2.60 Bcf/day in 2025 and by a further 0.80 Bcf/day, to 3.40 Bcf/day, in 2030.

The British Columbian LNG export projects will generate economic benefits both during construction of the pipeline and liquefaction and terminal facilities as well as during their operation. The operations will involve the ongoing development of new production facilities (continual well drilling), production of the gas, processing to remove by-products and waste materials, transportation to the liquefaction facilities, transformation of the gas to LNG, and loading the LNG vessels.

3 Gross economic impacts from construction and operation of gas pipelines and LNG export facilities

The construction of pipelines to transport natural gas from northeast British Columbia to the west coast for export to the Asia-Pacific region would have substantial direct and indirect economic impacts.[8] For example, based on Input-Output Model analysis of the economic impacts from construction of a hypothetical natural gas pipeline (undertaken for the Canadian Energy Pipeline Association), construction of the Pacific Trail Pipeline is estimated to contribute at least $650 million in nominal 2011 dollars to Canadian GDP and generate approximately 8,000 jobs (directly, indirectly, and as the result of induced effects), during the year of construction.[9] Virtually all of the direct GDP and employment impacts would be in British Columbia. Approximately one quarter of the indirect and induced impacts would be in the rest of Canada, especially in Ontario and Quebec (Angevine Economic Consulting Ltd., 2005).

8 Direct benefits are those enjoyed by companies that provide materials and equipment directly to the project and by workers and contractors who are directly engaged in construction. Indirect benefits are the impacts on employment and GDP that occur as the result of orders received by suppliers to the companies that are affected directly. The benefits referred to here, as with other impacts estimated via input-output model analysis, refer to the gross value added rather than net impacts. That is, they do not take account of GDP and employment reductions that occur if, for example, workers relinquish employment in order to work on the construction project that is being assessed.

9 The estimates of the impacts on GDP and employment from natural gas pipeline construction provided here are derived from estimates contained in "The Economic Impacts of Constructing an Energy Pipeline," a report prepared by Angevine Economic Consulting Ltd. in 2005 for the Canadian Energy Pipeline Association (Angevine Economic Consulting Limited, 2005). As noted earlier, these and the other economic impacts discussed in this section are gross; factors that could partially offset the potential economic benefits arising from such impacts, such as increased labor costs, are not addressed. Construction impacts are from input-output model simulation results that are based on the assumption that construction takes place in a single year. The indicated number of jobs is therefore in terms of job years.

Using the estimated impacts on GDP and employment as the benchmark, the Coastal GasLink (initial capacity) and the two additional new gas pipelines that we assume would be built would contribute at least an additional $2.3 billion (2011 dollars) to Canadian GDP and some 28,000 total additional job-years of construction employment.[10] Assuming that doubling the capacity of the Coastal GasLink pipeline to accommodate the third and fourth trains at the LNG Canada facility would have three quarters the impact of the initial construction, another $750 million and 9,000 job-years of employment would be added to the construction impacts. The construction of new gas pipeline transportation capacity to the west coast is therefore estimated to contribute about $4 billion to Canadian GDP and some 45,000 job-years of employment.[11]

Kitimat LNG Inc. projects that about 1,500 job opportunities will be created during the construction of its terminal (Kitimat LNG, 2010). We have assumed that these would be full-time positions and that the project would be built in one year, in which case the reference is to 1,500 job-years.[12] Using that benchmark, construction of LNG export terminal facilities by BC LNG Export Co-operative and by Shell and its partners (all four trains) would create approximately 300 and 3,750 job-years of employment, respectively.[13] Similarly, considering their size, construction of terminals to receive and liquefy gas at the two additional LNG projects that we assumed would be constructed (i.e., Project A and Project B) would give rise to approximately another 2,800 job-years of employment. Construction of all of the LNG liquefaction and terminal facilities is therefore estimated to create approximately 8,350 job-years of employment.[14]

10 The Coastal GasLink Pipeline running from near Dawson Creek to Kitimat, British Columbia, would be about 700 kilometers long (TransCanada, 2012). We assume that the other new pipelines would be the same length as the Pacific Trail Pipeline: 464 kilometers.

11 The expansion of Pacific Northern Gas (PNG) would also contribute to GDP and create additional employment opportunities, although these benefits would be considerably less than those from the construction of the much larger PTP facility. For this reason, the GDP and employment impacts from building the pipeline infrastructure required to transport the assumed LNG export volumes would undoubtedly be greater than indicated here.

12 The information about project benefits provided by Kitimat LNG simply refers to "1,500 construction jobs" (Kitimat LNG, 2010).

13 These estimates are based on the relative capacity of each project, Because the relationship of construction jobs to plant capacity is most likely not linear, these estimates are intended as rough approximations. The number of construction jobs per unit of capacity is likely greater with smaller plants such as the BC LNG Export Co-operative's facility than with larger ones such as the proposed LNG Canada project.

14 No estimates of the contributions to GDP from construction and operation of the LNG liquefaction and terminal facilities were publicly available.

Operation of Kitimat LNG will require 100 full-time jobs (Kitimat LNG, 2010). On that basis, but also taking the relative scales of their operations into account, we assume that the BC LNG Export Co-operative and LNG Canada (Shell et al.) projects will result in 25 and 230 full-time operating jobs, respectively. Based on the information for Kitimat LNG, we estimate that the two additional LNG projects that we assumed could generate about another 180 employment opportunities, bringing the total number of full-time jobs needed to operate all five of the assumed LNG facilities to about 535 jobs on a continuing basis. At $79,585 per job (Alberta Learning Information Service, 2012), this would contribute $42.6 million to labour income in British Columbia each year (and approximately the same amount to the provincial GDP).[15]

Operation of the Pacific Trail Pipeline (PTP) to transport natural gas from the Spectra BC gas transmission system to the Kitimat LNG export terminal will require a number of full-time and part-time workers, as will the GasLink pipeline and the two other pipelines that we assume will be built. Assuming that operation and maintenance of all three pipelines would add 400 permanent full-time equivalent jobs to the British Columbian economy at a cost of $79,585 per job (Alberta Learning Information Service, 2012), once built the pipelines would directly contribute $31.8 million to labor income in the province each year.

Table 6 summarizes the indicated economic impacts from the construction and operation of the LNG export facilities assumed in our development scenario and from construction and operation of the additional pipeline infrastructure. It is important to note that the estimated gross income and employment benefits from construction and operation of new pipelines to transport natural gas from northeast British Columbia to port facilities on the west coast, and the required LNG gasification and export terminals, do not reflect the impacts of the investment that will be required in natural gas gathering, processing and transmission facilities to move the gas to points on the Spectra Transmission System (e.g., Summit lake near Station 2) from which they can be shipped to the coast. Similarly, the economic impacts from facilities construction and ongoing operations associated with gathering, processing, and transporting gas to Dawson Creek for transfer to TransCanada's proposed GasLink pipeline have not been estimated.

15 The estimated cost per job is derived from the 2011 mean hourly wage of $38.38 for workers in the Alberta petroleum, gas, and chemical process operations group (Alberta Learning Information Service, 2012). This group includes gas pipeline operating and maintenance workers. The indicated hourly rate was inflated by 8% to account for vacation and other benefits. It was assumed that there are 48 forty-hour work weeks per year. If the indirect and induced impacts were considered, the total impacts from operations would be found to be greater than this. ("Induced" impacts in this case refer to economic impacts that result from the spending of labor income by persons directly or indirectly employed in the operation of the pipelines.)

Table 6: Gross economic impacts from construction and operation of gas pipelines and LNG terminals

	Natural gas pipelines	LNG terminals
Construction		
GDP	$3.7 billion (2011 $)	Not available
Employment	45,000 job-years	8,350 job-years
Operations		
Long-term jobs	400 full-time jobs	535 full-time jobs
Annual direct impact on labour income (and GDP)	$31.8 million (current $)	$42.6 million (current $)

Sources: Angevine Economic Consulting Ltd., 2005; Kitimat LNG, 2010; authors' estimates.

Ongoing gas-field operations to develop and produce increasing volumes of natural gas from the shale and tight gas resource locations in northeast British Columbia would also require an increasing number of workers. By 2035, when according to our development scenario production of unconventional (mostly shale and tight) gas in British Columbia is estimated to reach about 10.3 Bcf/day (compared with 1.3 Bcf/day in 2010), considerably more workers would be directly employed drilling new wells, providing services to wells that are operating, and in managing ongoing production than is the case today. Based on information reported in a study of the economic contributions of the Canadian natural gas industry by IHS Global Insight, we estimate that approximately 6,400 additional workers would be employed (IHS Global Insight, 2009).[16] Of course, development of LNG export capacity (including the necessary gas pipeline infrastructure) significantly greater than we have assumed would result in correspondingly greater benefits. For example, if the mammoth LNG export facility that BG Group PLC and Spectra Energy Corporation recently indicated they are considering for Prince Rupert were to proceed, the LNG export volumes identified in our development scenario could increase by 50% or more (Healing, 2012, September 10).

4 Improved netbacks and earnings

In addition to the contributions to employment and GDP from the construction and operation of LNG export facilities, Canada would benefit from the increased netbacks to the natural gas producers. If, as in our

16 It is estimated that approximately 1,975 workers are required in British Columbia for the production of natural gas at the rate of 1 trillion cubic feet per year or 2.74 Bcf per day (IHS Global Insight, 2009).

assumed BC LNG export development scenario, approximately 34.9 trillion cubic feet of gas were produced and exported to the Asia-Pacific market region during the period from 2014 to 2035 and the netbacks to the producers were, as Kitimat LNG Inc. (2010) has suggested, in the vicinity of $3.85 per Mcf (in 2010 constant dollar terms) greater than if the same volumes were sold in the United States, a net gain of about $134 billion 2010 dollars would be realized.

Some of the extra sales revenue would flow to shareholders and some of it would be re-invested. Although some of the shareholders reside in other countries, the incremental income distributed to Canadian shareholders would, as it is spent, have favourable economic repercussions as a result of induced employment, labor income, and GDP growth across the country.

Many pensioners who do not directly own shares in these companies would nevertheless benefit because the Canada Pension Plan Investment Board, other public-servant pension plans, and many private pension plans invest a portion of their holdings in shares of natural gas producing and transportation companies (Canada Pension Plan Investment Board, 2011). The value of the pension funds will appreciate as the net asset value of the companies whose shares they hold increases because of expanded production and transportation volumes. Also, the funds' revenues will increase as companies increase returns to shareholders through dividends.

Provincial and federal governments would benefit from greater corporate taxes because of the increased sales revenue and also from greater personal income-tax revenues as shareholders report investment income. Construction and operation of the infrastructure necessary to transport natural gas from northeast British Columbia to liquefaction facilities on the west coast, and to ship it as LNG to the Asia-Pacific region, would contribute about $4 billion to GDP, and create more than 53,000 job-years of construction employment and approximately 935 full-time equivalent operational jobs that would bring substantial economic benefits not only in British Columbia, but in other parts of Canada. The envisaged benefits encompass large numbers of temporary (construction) and permanent jobs, increased labor and investment income, and greater economic growth than otherwise. The resulting growth in federal and provincial government revenues would help to support essential education and health programs. Moreover, it would improve the governments' fiscal positions and, in some cases, allow for tax reductions that could improve the ability of households to meet their financial objectives.

Considering, also, the economic benefits that would flow from increased LNG export revenues as the result of securing markets in the Asia-Pacific region, the potential contribution to Canadian economic development would be considerable. While undertaking a comparison of the likely economic consequences with those resulting from former nation-building

events in the country's history such as the building of the transcontinental railways and construction of the TransCanada natural gas pipeline is beyond the scope of the present study, the economic impacts from constructing facilities for exporting LNG to the Asia-Pacific region and their long-term operating impacts are bound to be significant. Unfortunately, unnecessary regulatory procedures are either preventing the required infrastructure development from proceeding or needlessly slowing its progress. These are examined at some length in the next section.

Obstacles to LNG exports from British Columbia

1 Time and cost of regulatory process and procedures

Considerable time is frequently required from when an application is filed with the National Energy Board (NEB) for permission to construct a pipeline or a related facility for oil or natural gas exports until a decision is made on the application. Consider the long regulatory process that is unfolding as the NEB reviews the application for the proposed Enbridge Northern Gateway Project, which comprises an oil export pipeline, a condensate import pipeline, and storage tank and marine terminals at Kitimat, BC. Given the economic opportunities from LNG exports to markets in Asia-Pacific countries that we have outlined, regulatory proceedings that are drawn out to this extent will be extremely costly in terms of unrealized employment, labor income, and economic growth. Taxpayers will also suffer since, potentially, the foregone tax revenues from a project's construction and operation could be used toward tax reductions.

In general, the responsible government agencies appear oblivious to the commercial and economic costs of protracted regulatory approval procedures and the possibility that Canada could lose huge amounts of investment to competing petroleum exporting nations with more efficient and less costly regulatory requirements or that such projects could be delayed indefinitely (Angevine and Cervantes, 2011). The NEB has a self-imposed "service standard" that requires that it endeavour to have 80% of its reasons for a decision completed and released within 12 weeks following the completion of a public hearing (National Energy Board, 2011c). However, there is no guarantee that the target will be achieved and there are no incentives for the NEB's staff to strive to ensure that it is. Further, the service standard does not apply to hearings that involve the issuance of a separate Environmental Assessment Report requiring a government response or a decision by the Minister of the Environment.[1] Moreover, the Board has no service standards

1 Presumably, it also does not apply in the case of a Joint Review Panel charged with examining a project from the perspective of both the Canadian Environmental Assessment Act and the National Energy Board Act.

pertaining to the time from when an application is filed until a public hearing commences and no time constraints are set for the public hearing itself.

The National Energy Board's request that "project descriptions" be provided by a major project proponent at least six months from the intended date of filing of the applications is designed to help Board staff plan for the scrutiny of applications and for hearings (National Energy Board, 2011c). By discussing project plans with the Board before an application is filed proponents can work to ensure that information requirements for an application are fully met at the date of filing, thereby avoiding the extra time and cost of extensive revisions. However, in and by itself the requirement of six-months advance notice appears to add to the time required to gain project approval.

Perhaps in part because the Joint Review Panel that was put in place to examine socio-economic and environmental implications of the proposed Mackenzie Gas Project took so long to complete its task and report its findings to the National Energy Board, the federal government has moved to award responsibility for environmental assessment (EA) under the Canadian Environmental Assessment Act (CEAA) in relation to a project application being examined by the National Energy Board to the NEB itself instead of to a separate review panel under the CEAA. This will provide the Board with the ability to manage the environmental assessment in step with and in conjunction with its responsibilities in relation to pipeline project applications filed in accordance with the National Energy Board Act.[2] According to Section 52 of the Act (which deals with pipelines) these responsibilities include consideration of: 1. the availability of oil or gas to supply a proposed pipeline; 2. the existence of actual or potential markets; 3. the economic feasibility of a proposed pipeline; 4. the financial responsibility of the applicant; 5. methods of financing the pipeline; and 6. the extent to which Canadians will have opportunities to participate in the financing, engineering, and construction.

Regulatory procedures and processes in relation to major project applications before the NEB and other regulatory bodies around the world are not only arduous and long (and therefore costly) but essentially unpredictable in terms of time and cost. Because of these costs and uncertainties, applications in relation to many feasible energy projects no doubt never materialize, in which cases the projects simply do not get built.[3] In some cases, developers

---

2 The National Energy Board approves pipeline traffic, tolls, and tariffs under the authority of the National Energy Board Act.

3 The authors are unaware of evidence that suggests that this only applies to projects with marginal profitability. Even projects with the potential for above-average returns may be at risk of being foregone if arduous regulatory obligations cause would-be applicants to turn projects in other jurisdictions or with less economic potential.

may instead decide to invest in similar projects in jurisdictions where the cost of regulatory compliance and the probability of securing approval within reasonable time frames are more attractive.

The Government of Canada's plan for "Responsible Resource Development" announced in April 2012 indicated that the government was not only aware of the economic burden imposed by inefficient regulatory procedures and processes with regard to energy project applications but prepared to act to ensure that regulatory reviews are completed in a more timely and predictable manner and that the extent of duplication in the requirements of federal agencies and departments and between federal and provincial authorities is reduced (Natural Resources Canada, 2012). Among other things, the government planned to establish maximum beginning-to-end regulatory process timelines. Legally binding timelines were to be set for important regulatory permitting processes such as the review of project applications and provision of final reports with recommendations to the Minister responsible. Standard environmental assessments would need to be completed within 12 months, and National Energy Board's reviews (and decisions thereon) in 15 months. Reviews undertaken by joint panels such as those appointed by both the Minister of Environment and the Chair of the National Energy Board and decisions thereon would need to be completed in 24 months.

In order to reduce duplication, the Responsible Resource Development plan indicated that the government planned to consolidate responsibilities among federal agencies and to integrate federal and provincial regulatory requirements more closely. In addition, the federal government stated that it would seek authority through substitution and equivalency provisions to allow provincial environmental assessments that meet the substantive requirements of the Canadian Environmental Assessment Act to replace federal environmental assessments as a means of eliminating duplication between the two levels of government. Further, the government indicated that it would seek equivalency of Fisheries Act regulations with counterpart provincial regulations.

These various changes were enacted in the Jobs, Growth and Long-term Prosperity Act passed by Parliament in June of this year (2012). While the time limits required for decisions to be reached from when the responsible regulatory authority is satisfied that a project application is complete until the Minister responsible has received the authority's review and made a decision will help to ensure that the National Energy Board, joint review panels, and other federal regulatory authorities take a more businesslike approach to fulfilling their mandates, in our opinion the time constraints are too generous. For example, while NEB reviews of project applications under sections 52 and 58 of the National Energy Board Act are to be completed within 15 months, the Board may require the applicant to provide information or to conduct a study without regard to that time limit. Moreover,

the legislation allows the responsible minister to extend the time limit that the NEB has to complete its review for three months, following which the Governor in Council may, on recommendation of the minister, further extend the time limit "by any additional period or periods of time" (Government of Canada, 2012). In addition, while the responsible Minister (in effect, the government) is required to make a decision on a report submitted by the NEB within three months (increasing the total time required for a decision to be reached to at least 18 months), the Governor in Council may extend that time limit indefinitely.

Similar delays are permitted in the case of joint review panels. While the legislation requires that decisions by the responsible minister be reached within 24 months from the date when a review panel is established, the decision-maker may extend that time limit by up to three months, and the limit may be further extended for an unspecified period of time by the Governor in Council. Further, if a project proponent is required by the panel to collect information or to undertake a study, the time that is required is in addition to the stated 24-month maximum. These opportunities for time extensions in the review and decision-making processes suggest that a proponent of a major project generally will not know when filing an application how long the regulator will require to review it or how long the government will take to reach a decision on the reviewer's recommendations.

Duplication of applications for similar projects

It is further a matter of considerable concern, because of the regulatory burden and consequent costs imposed, that detailed applications must be filed with respect to closely similar projects that would be located in the same general area, even when little time has elapsed from when the first application is filed. For example, a public hearing was launched in June, 2011 to consider the application filed by Kitimat LNG in September, 2010 to export LNG from British Columbia's west coast to the Asia-Pacific region. A similar application, which BC LNG Export Cooperative LLC filed with the NEB in March 2011, was the focus of another public hearing during the first trimester of 2012. Although the duplication of regulatory process in relation to these closely related projects may have been lucrative for the teams of lawyers and other professionals that the project proponents assembled, the unnecessary procedural repetition inevitably added to the time and cost required to secure approval of the second application. The same will occur with similar applications that are expected to follow shortly.[4]

4 As explained in the following section in which we put forward a number of recommendations regarding policy reforms, we are not in favour of simply waiving requirements for "later" proposals. In some cases, that would simply provide an incentive for would-be applicants to delay filing with the intent of becoming a "later" applicant.

This kind of duplication, which is not addressed in the Jobs, Growth and Long-term Prosperity Act, will add to potential LNG exporters' costs. Because the price of LNG in the Asia Pacific region is determined by local and regional market forces, Canadian LNG exporters are, essentially, price takers. The result is that the incremental regulatory burden arising from the duplication of regulatory procedures must ultimately be borne by the shareholders of the companies using the LNG liquefaction facilities. As a consequence, faced with costs and regulatory delays greater than expected, some investors may decide to turn their attention from Canada to similar opportunities in other countries.

The challenge of regulatory procedure and process duplication will also arise in relation to applications to construct and operate pipelines to transport natural gas from conventional and unconventional (shale) gas supply sources in northeast British Columbia to LNG liquefaction and terminal facilities on the west coast. With present procedures, regulatory review costs for pipeline projects that follow in the wake of successful applications filed for very similar projects in the same region are routinely incurred even though there may be no or little need to scrutinize applications so similar to those already approved. Another concern is in cases where separate applications for proposed pipelines and export facilities must be filed with different regulators with respect to the same LNG export project (with the same proponents). For example, in February 2011 Apache Canada and EOG Resources Canada, proponents of the already approved Kitimat LNG facility, bought 50% of Pacific Trail Pipeline (PTP) from Pacific Northern Gas (PNG). While the purpose of PTP is to supply the natural gas liquefaction facility at Kitimat with gas, separate applications for construction permits were required for the LNG export facility and the pipeline—Kitimat LNG through the National Energy Board and PTP through BC Oil and Gas Commission—even though both are needed for the same overriding objective: to export natural gas in the form of LNG to the Asia Pacific.[5] In cases like this it would be more efficient if both projects were subject to approval, preferably at the same time, by just one regulatory body.

2 Conflicting toll-setting methodologies on federally regulated pipelines

In northeast British Columbia, the likely source of most of the natural gas supplies for LNG export facilities on Canada's west coast, tolls for Spectra Energy (operating as Westcoast Energy) Transmission System gathering and process services, including transportation on extensions built to facilitate

5 This is because the pipeline is solely within British Columbia and therefore regulated by BC government authorities under the laws of the province, while the approval or rejection of natural gas exports fall under federal jurisdiction.

the movement of raw gas to processing plants, are being determined differently from tolls on extensions of the TransCanada Alberta System (i.e., Nova Gas Transmission Ltd. or "NGTL") such as the Groundbirch Pipeline into the region. The so-called "Framework for Light-handed Regulation" that was negotiated with stakeholders and approved by the National Energy Board in the mid-1990s, provides for market forces (as reflected in negotiations) to determine the tolls on the Westcoast Energy System (National Energy Board, 1998). On the other hand, tolls on NGTL expansions into northeast British Columbia are determined by rolling the incremental costs into NGTL's Alberta-wide rate base.[6]

Application of different pricing methodologies means that tolls on extensions of the NGTL system into northeast British Columbia are likely to be much lower than the negotiated stand-alone, cost-based tolls that apply to extensions on the Westcoast System. The contention by Westcoast that this "subverts meaningful competition in the development of new pipelines in the region and has long-term consequences for investment decisions, the location of pipelines and gas processing facilities, gas flows and the utilization of new and existing facilities in the region" appears in our view to have some merit (Spectra Energy, 2011: 7). For the reasons indicated, the application of different methodologies for determing rates could impede development of the extended pipeline gathering system that will be required to collect natural gas for delivery to gas liquefaction facilities on the British Columbia coast. In any case, there is no reason that more than one toll-setting methodology should apply to pipelines regulated by the National Energy Board that are operating in the same part of the country.

3 First Nations' lands

An obstacle to energy project development across land where First Nations are present without treaties has, at times, been the claims of ancestral rights or stewardship responsibility with respect to the land. Unlike the situation in most of the rest of Canada, in British Columbia most native bands are living on Indian Act reservations and do not hold title to the lands upon which they and their ancestors have depended for generations. Further, they do not have the right to self-government; their economic and social needs being met by administration of regulations under the federal Indian Act. To address these issues, the BC Treaty Commission is striving to negotiate treaties with First Nations that do not have agreements with the provincial government. Treaties generally award the right to self government and to ownership of at least portions of ancestral lands. British Columbia's First Nations with treaties must generally abide by provincial legislation pertaining to matters such as

6 Until recently, Nova Gas Transmission Ltd. (NGTL) was regulated by Alberta's Energy Resources Conservation Board.

environmental protection, health, and education but the treaties respect the need to preserve cultural traditions. Property rights and mechanisms for resolution of disputes that are embedded in treaties and help clarify native rights with respect to their territories are said to facilitate economic development (BC Ministry of Aboriginal Relations and Reconciliation, 2011). Moreover, if a First Nation has a treaty agreement with the government, then prospective investors know precisely who to negotiate with and on what basis.

In the case of First Nations without treaties that claim to have "unceded aboriginal rights and title" over tracts of land, the extent of their property rights are essentially undefined (Carrier Sekani Tribal Council, 2006). However, a non-treaty First Nation that successfully asserts "title" to land in court has a degree of control over how the land is developed (Penty, 2011, November 21). Proponents of energy pipelines that would cross reservations and other lands occupied by non-treaty native groups must therefore work diligently to convince such groups that construction and operation of the projects would be in their interest. If First Nations who would be directly affected simply dig in their heels and say "no," then it may prove very difficult to overcome their opposition.

An impact and benefit agreement (IBA) is typically sought between a resource developer and affected aboriginal communities to address the impacts of a proposed project and to outline how those communities will benefit from the project—that is, to establish the relationship between the communities and the proponents of the project. IBAs may be reached with or without government involvement. When the federal or provincial governments are involved, such participation generally reflects the obligation that governments have to consult with aboriginal groups on resource development issues (Isaac and Knox, 2010). But the extent of the required consultation and what constitutes fulfillment of the obligation are not well defined. Moreover, if aboriginal groups do not heed the advice that is offered by the Crown, it is unclear whether the Crown has the right to force its will upon such groups.

Impact and benefit agreements take many forms and are highly dependent upon the specific features of the project, including the nature of the resource to be developed and the location. They often address such factors as training and employment opportunities; social, cultural, and community support; environmental protection and monitoring; and financial benefits such as revenue sharing and compensation provisions.

Resource project development is frequently stymied or delayed, sometimes indefinitely, because of the inability of the project proponents and First Nations groups to agree on compensation aspects of a proposed IBA. Recently, resolution of the compensation issue in relation to energy pipelines has begun to focus on encouraging and assisting First Nations groups whose lands would be affected to acquire an equity position in the pipeline. This approach provides an ongoing flow of revenue to First Nations that is directly tied to operation of the pipeline.

In the case of the proposed Mackenzie Gas Project, the project proponents agreed to provide an equity interest in the Mackenzie Valley (gas) Pipeline to First Nations bands through whose lands the pipeline would run. Agreement has been reached on this basis with the Sahtu, Gwich'in, and Inuvialuit, the present shareholders of the Mackenzie Valley Aboriginal Pipeline Limited Partnership (the Aboriginal Pipeline Group or "APG") that has acquired a one-third interest in the Mackenzie Valley Pipeline. The fourth band whose lands would be affected by pipeline, the Decho, is the only band with which agreement has not yet been reached. Given that they stand to benefit through APG's equity position in the pipeline, the Sahtu, Gwich'in, and Inuvialuit are supportive of the larger project. APG's equity in the pipeline has been financed via a loan from a group of banks (Aboriginal Pipeline Group, 2011).

Another example where providing equity ownership appears to have been instrumental in allowing an agreement to be reached between project developers and First Nations groups that would be affected is found in British Columbia. In 2009, the BC government agreed to assist 15 of the 16 First Nations across whose lands the proposed 463 kilometer Pacific Trail Pipelines (PTP) would pass to obtain a 30% ownership interest in the project, which is estimated to cost about $1 billion. The initial support came in the form of a $3 million incentive for the First Nations to ratify the agreement and a further $32 million grant to secure their equity position (BC Government, 2009). Pacific Trail Partnership Limited will also provide up to $8.5 million to First Nations groups involved in the project. PTP will connect the Spectra Energy (Westcoast) Transmission pipeline system at Summit Lake to the Kitimat LNG terminal. The one First Nation of the 16 with bands living along or near the path of the proposed pipeline that had not agreed to support the PTP proposal at the time of writing is the Wet'suwet'en Nation (Penty, 2011, November 21). Representatives of two of that Nation's clans (the Likhts'amisyn and the Unist'hot'en) turned back a PTP work crew on a logging road in British Columbia in November, 2011. Those clans represent only a small number of the estimated 2,500 strong Wet'suwet'en Nation. Further attempts to disrupt the project could probably be thwarted through appropriate legal action although this might be somewhat complicated by the fact that the Wet'suwet'en do not yet have a treaty with the provincial government. If, as a last resort, government intervention is required, that should not pose a political dilemma given the overwhelming support for the project by the 15 other First Nations that would be directly affected by the project.

It is estimated that the First Nations bands along the pipeline route could benefit from cash flows totaling as much as $570 million over the life of the 25-year agreement. Each band will benefit according to the portion of the PTP in its territory. This represents the first time that so many First Nations groups in British Columbia have joined together for a business venture (Billard, 2011). The 15 First Nations that have agreed to support the PTP project will also

receive $18 million from Human Resources Development Canada for training to assist 600 people to secure employment in resource development activities and serve the pipeline project. The overall package includes an essential agreement on environmental issues, including monitoring procedures.

In order to convince the Haisla First Nation to agree to allow the proposed Kitimat LNG Terminal to be built on Haisla reserve land at Bish Cove on Douglas Channel, the project proponents provided the Haisla with an option to purchase an equity position in the project. The Haisla then sold their option back to the proponents for $US 5.0 million. The Haisla Nation will also benefit from regular lease and property tax payments, as well as from employment and business opportunities, if the project succeeds (Kitimat LNG, 2011). [7]

4 Environmental Hazard Issues

There are also environmental issues arising from the construction and operation of new pipelines to transport natural gas to LNG terminals along the BC coast as well as from LNG liquefaction and shipping. But, natural gas leaks do not pose nearly as much of a problem as oil spills since escaping gas soon mixes with the surrounding air mass.[8] Although explosions of natural gas pipelines, liquefaction facilities, and LNG tankers pose a threat to people, forests, and fauna, with careful management practices their occurrence can be minimized. If explosions do occur, the damage can generally be confined and the ensuing clean-up is of a much smaller and more manageable nature than that required by an oil spill.

The Canadian Energy Pipeline Association defines "significant failures" on oil and gas transmission pipelines as incidents with one or more of the following characteristics (CEPA, 2011):

1. caused a serious injury or fatality;
2. caused a liquid release of greater than 8 cubic meters (50 US barrels);
3. produced an unintentional ignition or fire; or,
4. occurred as a rupture.

---

7 The Haisla have also entered a 50-50 cooperative agreement with LNG Partners of Houston to build and operate a smaller LNG export facility near Bish Cove (near Kitimat, British Columbia).

8 While natural gas leaks add carbon compounds that are associated with climate change to the atmosphere, in the short time that would elapse before a leak would be discovered and stopped the volume of carbon compounds entering the atmosphere would be very small compared to total GHG emissions per year from Canadian natural-gas production and processing. Those activities account for about 9% of Canada's GHG emissions in terms of tons of carbon equivalent but a very small proportion of global GHG emissions (Environment Canada, 2011; *Environmental Leader*, 2011, May 31).

Significant failures on Canadian natural gas pipelines are rare and the frequency of their occurrence has been declining. This is indicated by table 7, which shows that the number of incidents of significant failure has generally declined since 2002 (CEPA, 2012). During the period from 2002 to 2011, on average, there were only 1.7 significant failures per year. On a per-kilometre basis, such incidents averaged 0.026 per thousand kilometres of pipeline.[9]

A study by the Interstate Natural Gas Association of America (INGAA) indicates that in the United States the risk of failures in long-haul natural gas transportation by pipeline is also very low. The INGAA's study indicates that according to data from the US Department of Transportation, operators of natural gas transmission pipelines averaged five serious incidents per year between 2000 and 2010 along the approximately 300,000-mile natural gas transmission network in the United States (INGAA, 2011). In spite of the low incidence of serious incidents, ongoing monitoring of pipeline operations is very important.

One of the more common causes of failure in natural gas pipelines is operation outside of the physical design limits when operators attempt to maximize throughput volumes (Chis, 2007). If a pipeline is designed to operate within specified pressure ranges, then operation at higher pressures can result in rupture. Pipeline inspectors appointed by the regulator (or the provincial or state agency in question in the case of non-regulated pipelines) help to ensure that pipeline operators do not exceed the approved pipeline operating limits.

An effective monitoring process used before a new natural gas pipeline is approved for operations is to send so-called "smart pigs" through the line. These are mechanical devices capable of detecting and measuring thickness and integrity as well as the extent of any corrosion. The process is therefore an effective means for identifying the risk of failure so that repairs can be made before a leak occurs. Although the use of smart pigs is becoming normal practice during pipeline construction, regular line inspections employing smart-pig technology after a pipeline has entered service will help to reduce the likelihood of pipeline leaks further.

Some pipeline companies undertake risk assessments of "High Consequence Areas" (HCAs) as part of their regular integrated management planning processes. Typical HCAs include areas with high population densities, facilities such as hospitals or schools that are difficult to evacuate, and locations such as churches, office buildings, or stadiums where people congregate. Risk assessments of HCAs help to identify which pipeline segments pose the greatest risk to the population and to the environment. Moreover,

9 Table 7 indicates that some natural gas was released in 2004 and 2010 in spite of the fact that there were no significant failure events in those years. This reflects the fact that releases can occur without there being a significant failure.

Table 7: CEPA Members' Natural Gas Pipeline Integrity Performance

	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011
Pipeline length (1000 km)	62.0	62.2	62.2	62.4	70.8	71.3	72.1	72.0	74.2	72.0
Number of significant failure incidents	4	3	0	2	2	0	1	4	0	1
Nunber of significant failure incidents per 1000 km	0.064	0.048	0	0.032	0.028	0	0.014	0.056	0	0.014
Gas released (106 m^3)	7.310	5.770	6.200	0.900	0	0	4.070	7.760	0.020	2.790
Number of fatalities	0	0	0	0	0	0	0	0	0	0

Source: Canadian Energy Pipeline Association, 2012.

the process compels pipeline operators to evaluate the capability of various automated systems to detect leaks and to determine whether equipment needs to be replaced, upgraded, or duplicated.

The Canadian Energy Pipeline Association encourages its members to develop integrated management plans that include HCA risk assessments in order to ensure that their pipeline operations are environmentally responsible and that the companies are prepared to respond to accidents or pipeline malfunctions in a timely manner. If companies are not willing to do this on their own, government officials who are responsible for pipeline safety should encourage them to do it.

Once a pipeline is operating, providing accurate, comprehensive information about a leak or spill to groups that may be affected as soon as possible will help them to decide whether they need to become involved in mitigation processes.

The hazards from an LNG tanker leak vary depending on the size and duration of the spill, environmental conditions, and the site at which the leak occurs. Hazards can include cryogenic burns to the ship's crew and people nearby or damage to the LNG ship from contact with the cryogenic LNG. Vaporization of the liquid LNG can occur once a spill occurs and subsequent ignition of the vapour cloud could cause fires and overpressures that could injure people or cause damage to the tanker's structure, other LNG tanks, or nearby structures (Hightower et al., 2004).

Since the global LNG shipping industry began in 1959, only eight marine incidents worldwide have resulted in LNG spills, mostly caused by structural damage to the LNG carriers. These accidents have caused some minor damage; but no cargo fires or fatalities have occurred (Hightower et al., 2004). In case of an accidental LNG spill, the most significant impacts upon public safety and property exist within approximately 500 meters of the spill, due

to thermal hazards from fires, with much lower effects upon public health and safety at distances beyond approximately 1600 meters. Releases of LNG vapour are unlikely but, if the vapour does not ignite immediately (with risk of injury and property damage), the chance of directly harmful effects upon people dissipates as the vapour turns to gas (Hightower et al., 2004).[10]

5 Environmental assessments

In June, 2008, Pacific Trail Pipelines Limited (PTP) received a provincial environmental assessment (EA) certificate for the Kitimat-Summit-Lake Pipeline Project following a comprehensive review process undertaken by the BC Environmental Assessment Office. In addition to the provincial EA, the project also required approval by the federal government under the Canadian Environmental Assessment Act. A favourable federal decision was made in March, 2009. It would have been more efficient if a joint federal-provincial environmental review had been undertaken.

As previously indicated, the construction and operation of a gas pipeline and an LNG export terminal could be proposed by the same group of investors. In fact, this has recently occurred in the case of the PTP and the Kitimat LNG facility. In this case, separate environmental assessment reviews were required. Surely, it would have been more efficient, and less costly, to have had a single, combined review embracing both the pipeline and the natural gas liquefaction facility and terminal.

In the next section, we outline how, working together, governments could lower and in some cases remove obstacles that stand in the way of the infrastructure development that will be required if we are to take advantage of the nation-building opportunity that securing access to LNG markets in the Asia-Pacific region represents. This would involve, first and foremost, addressing the legitimate concerns that some individuals, families, land owners, and First Nations have about construction and operation of the required natural gas pipelines and other facilities. This would require balancing the rights, interests, and aspirations of individuals and groups with the economic and social benefits that securing LNG markets can bring.

10 There would ,of course, be some greenhouse gas (GHG) emissions. However, in the case of uncontrolled decompression not accompanied by combustion from a LNG vessel containing say, the equivalent of 1 Bcf of gas, the contribution to GHGs would be small relative to annual Canadian and global emissions.

Policy options

The obstacles outlined in the preceding section are impeding the development of the pipelines, liquefaction, and port facilities needed to produce and ship LNG from the west coast, thereby preventing Canada from taking full advantage of market opportunities in the Asia-Pacific region that are key to substantial growth of production of British Columbia's natural gas resources. These obstacles are keeping the benefits, employment, and income opportunities that citizens of British Columbia and Canada could have if such development were to proceed beyond their grasp. This section identifies policy options that could remove or significantly lower obstacles to developing the infrastructure essential for Canadian economic development and prosperity. If Canadians desire to develop British Columbia's natural gas resources expeditiously and efficiently in the current market conditions, legitimate environmental concerns, and global investment opportunities, then discussion of the required policy framework is necessary.

1 Time and cost of regulatory procedures

1.1 The National Energy Board Act could be revised to restrict the scope of the National Energy Board's authority to matters necessary to protect the public interest: that is, construction and operational standards and efficiency, property rights and claims, and environmental impacts. Consequently, the NEB would no longer be involved in investigating the commercial feasibility and risks associated with proposed capital investment as these would presumably be examined by the project proponents as risk takers and the ultimate users of the facilities, the companies shipping natural gas. Similarly, the NEB would no longer need to be concerned with the quality and extent of markets that a facility would serve, the availability of gas to the pipeline, the financial structure of the applicant, or how a project is to be financed.[1]

1 The NEB would continue to be responsible for determining whether proposed volumes of exported gas are in the public interest given the outlook for domestic natural gas production and demand. But a decision to issue an export license in the light of a favourable decision by the Board would be left to the federal government.

Of course, the NEB would continue to regulate tolls on pipelines that fall under federal jurisdiction.[2]

By way of example, the National Energy Board Act might be revised to remove the NEB's mandate to consider opportunities for Canadians in the design and construction of a proposed pipeline. There are at least two reasons for this: the North America Free Trade Agreement was not in place when the National Energy Board Act was enacted; and it is generally recognized that employers should have the economic freedom to employ those skilled and unskilled workers who are best suited for the job.[3]

Reducing the scope of the Board's involvement in this manner would shorten the time required for the NEB to arrive at decisions on project applications. It would also result in lower regulatory compliance costs since the Board would no longer be required to assess information about the economic feasibility of a project, including the ability of the targeted markets to absorb the gas to be exported. Further, the restricted scope of the NEB's surveillance would reduce the potential for extensive regulatory duplication and repetition in assessing closely similar projects.

1.2 Discussion of the required policy framework might conclude that it makes sense to establish limits on the number of registered interveners that can be heard at a public hearing in order to prevent special-interest groups from unnecessarily dominating and prolonging the hearing process. This can be managed by allocating a specified amount of time to representatives of each of the stakeholder groups (e.g., the project proponents, other industry participants, government agencies, landowners, First Nations, non-government organizations, and the general public). This would ensure that none of the stakeholder groups is able to command an inordinate amount of time (more, say, than several days) to express their opinion. As a consequence, the time required to complete the oral hearings with respect to any project application could be limited to some reasonable time period, perhaps not exceeding 30 working days.

1.3 A policy review might also conclude that shorter, more clearly defined, and real limits should be established on the time required for a federal regulator or joint panel to complete and submit a review of a project application to

2 Potential shippers would be responsible for examining the range of tariffs (and therefore cost risks) that they could expect to face during the lifetime of the project and, on that basis, decide whether to enter into commercial arrangements with the project proponent.

3 More exhaustive scrutiny of the National Energy Board Act would likely identify many other opportunities for improvement. However, before any revisions to the National Energy Act along the lines suggested here are made, more in-depth analysis would be required to ascertain that they would have no undesirable consequences.

the government and for the government to make decisions on the recommendations provided. These might range from 12 to 18 months from the date that an application is filed, depending on project size and complexity.[4] The review might also conclude that, unlike the provisions that recently came into effect under the Jobs, Growth and Long-term Prosperity Act, the circumstances under which extensions may be permitted need to be clearly defined and unambiguous limits placed on the total amount of time that the regulator and the government may take to reach a decision on a project application.[5]

1.4 Further, the National Energy Board could consider convening "generic" public hearings if two or more similar project applications affecting the same regions of the country (Alberta and British Columbia in this case) are likely to be brought forward during the next 10 to 20 years. At such hearings, the full range of issues common to such projects could be examined with a view to determining the public safety and environmental protection measures that prospective project applicants would be expected to undertake. Generic hearings could also establish export market volumes and so on and therefore eliminate the necessity for repeating the process with each application. In this manner, the extent to which fundamental issues would need to be addressed in considering separate project proposals would be reduced.

1.5 Governments of the province(s) involved, First Nations organizations, and the federal government could meet with industry representatives to identify and approve transportation corridors to be used to transport natural gas from the same regional points of origin (e.g., northeast British Columbia) to the same general destination points. The advance approval of transportation corridors would greatly reduce the potential number of land access and claim issues that would need to be addressed. Further, such issues would only need to be considered in depth once, that is, in relation to the first application that involves them rather than in each of a number of successive project applications.

4 This assumes that the application is "complete" in that it contains all of the required information as set out in the application filing criteria.

5 The Jobs, Growth and Long-term Prosperity Act of June 2012 sets out certain time limits for regulatory proceedings. For example, a maximum of 24 months for joint panel reviews and decisions under the Canadian Environmental Assessment Act, and 18 months for the review of a project application by the National Energy Board and for government to make decisions on the NEB's recommendations. However, not only may the time required by a regulator to review the information provided by a project proponent and interested parties be extended with government consent, but the government may.allow the responsible Minister an indefinite period of time to reach a decision. For a project proponent, this creates a great deal of uncertainty about when a decision is likely to be reached.

The federal government should probably play the lead role in identifying strategic energy transportation corridors with a sufficient right of way to accommodate all foreseeable projects. The need for consultation with First Nations organizations that would be directly affected by the construction and operation of new pipelines is essential and their reasonable concerns must be addressed. If the federal government, representing both the national interest and that of potential project proponents, and First Nations groups cannot reach agreement on the routes of transportation corridors or on what constitutes fair compensation for the use of land to which those groups have ancestral or treaty title claims, then the government might wish to consider project-specific legislation to break the impasse, ensuring, of course, that fair compensation is provided.

1.6 A policy review might also conclude that only a single application to construct a project is necessary when both an LNG liquefaction and port facility and a new pipeline are being proposed to export LNG. The combined project would then be subject to a single regulator, such as a joint federal-provincial panel. If the pipeline and the terminal that are being proposed were to be located in British Columbia, the project should fall under the scrutiny of the National Energy Board or a joint federal-provincial review panel.[6] This is because the pipelines and terminals will exist to export gas and the National Energy Board is accountable for gas exports under the National Energy Board Act. These changes would facilitate the review process by reducing the time and cost from that which would be required if separate applications to two or more different regulatory bodies were necessary.

2 Conflicting toll-setting methodologies on federally regulated pipelines

2.1 In order to avoid distortions of market-based investment decisions about the size and location of new federally-regulated natural gas pipelines, a review of the existing policy might recommend that the National Energy Board remove inconsistencies in the methodologies being used to determine tolls on federally-regulated natural gas pipelines in northeast British Columbia (as well as anywhere else in Canada where such discrepancies exist).

3 Objections by First Nations

3.1 Project proponents should generally discuss project plans with First Nations that would be affected well before their applications are filed with the NEB, a joint review panel and/or other government agencies including the

6 The National Energy Board does not regulate export facilities such as Kitimat LNG but recommends to the federal government whether export licenses should be issued.

federal Major Projects Management Office. Although only government (the "Crown") is required to consult with First Nations about the possible impact of proposed projects, early discussions initiated by project proponents would improve First Nation's understanding of what is being proposed before they hear about it second hand. This would promote an element of trust with the First Nations that what the proponent will eventually put forward to government in the form of a formal project proposal will fully reflect their concerns.

3.2 First Nations' concerns over the environmental impacts of proposed energy pipelines and other energy projects should probably be subject to environmental assessments under, and in accordance with, the Canadian Environmental Assessment Act in the same manner as environmentally based opposition to project development by other groups.

3.3 If the regulatory body responsible for undertaking the environmental assessment finds that environmental risks, including those of legitimate concern to First Nations, cannot be reduced, development should be refused. On the other hand, if the assessment concludes that the developmental and operational risks to the environment that are raised by First Nations can be successfully mitigated, and the project developers are willing to proceed knowing that they will be required to absorb fully the risk management and mitigation costs, then the review board or panel may decide to approve the project application if there is no other reason to reject it.[7]

3.4 Federal legislation and regulations that would provide for mandatory settlement (arbitration) mechanisms should be considered as a means for resolving disputes about compensation with First Nations that stand in the way of a project's proceeding if they remain unresolved a specified number of months following approval of a project application by the NEB or a joint panel.[8] If necessary to avoid inconsistencies with federal requirements in this regard, similar legislation should also be enacted in the provinces.[9]

---

7 In the absence of treaties, or even where treaties have been signed, First Nations' counsel may argue that the Crown does not have authority to approve construction of a pipeline through their territories because of their "ancestral" rights. If this occurs, the matter may be left to the courts to decide.

8 No new legislation may be required if the Expropriation Act is sufficiently clear regarding the right to expropriate land to which a First Nation holds treaty rights in cases where the project proponent appears to have fully satisfied the obligation to consult with that First Nation. Where contested, though, this could, once again, be a matter for the courts to decide.

9 If an issue is a provincial one, provincial legislation specific to that issue may be required.

Whereas First Nations (and others) may be adamantly opposed to arbitration as a means for settling disputes, in some instances it may be the only means to enable projects with substantial economic and social benefits to First Nations and to society as a whole to proceed. This may be necessary if First Nations are intransigent because of environmental or cultural concerns. Where the concern is about environmental issues a decision enforced by arbitration or special legislation must ensure that the project proponents are prepared to provide reasonable compensation. Where the opposition is based on spiritual perspective—for example, where it is claimed by First Nations that they would betray their ancestors if they agree to have the land altered in some way and that no amount of compensation would be acceptable—, there is no alternative to arbitration.

4 Environmental hazards

In order to reduce the risk of leaks in natural gas pipelines that will be needed to transport gas from the interior of British Columbia to the west coast the following guidelines are put forward for consideration:

4.1 operators of natural gas pipelines be required to undertake risk assessments in relation to high consequence areas as part of their integrated management planning;

4.2 gas pipeline operators be required to ensure that pipelines are not operated at greater than approved pressure levels and that severe penalties be established;

4.3 regulations be revised to require more frequent and thorough monitoring of pipeline condition and integrity in order to reduce the likelihood of failure incidents occurring.

5 Environmental assessments

Future pipeline projects that, like the Pacific Trail Pipeline, are needed to transport natural gas to the west coast, will require environmental assessments under both the Canadian Environmental Assessment Act (CEAA) and the British Columbia Environmental Assessment Act (BCEAA). Harmonized reviews are already contemplated by the Canada-British Columbia Agreement for Environmental Assessment Cooperation. In this regard, we suggest the following.

5.1 Joint federal-provincial environmental reviews be established for all natural-gas transportation infrastructure projects that require approvals from both levels of government or, alternatively, as per the Government of Canada's Responsible Resource Development plan, that provincial reviews that meet the requirements of the Canadian Environmental Assessment Act be substituted in place of a federal review.

Where a federal government agency in addition to the National Energy Board and/or Environment Canada (e.g., Fisheries and Oceans) is responsible for managing environmental risk under specific legislation, then such agencies and department(s), be jointly responsible for carrying out an environmental assessment. That is, as suggested in the government of Canada's Responsible Resource Development plan, responsibility for environmental assessment be consolidated under a single federal agency or, via equivalency provisions, ceded to a provincial environmental assessment that meets the key provisions of the Canadian Environmental Assessment Act.

5.2 A single environmental impact assessment be undertaken in relation to a proposed natural gas liquefaction/LNG export facility and a natural gas pipeline required to supply that facility. This will require the authorities to make a complete evaluation of the environmental consequences of all aspects of a project at the same time and request effective mitigation measures, given the ability of the common proponent to efficiently coordinate an environmental management plan for both facilities.

References

Aboriginal Pipeline Group (2011). *About APG*. <http://www.mvapg.com/about-apg.php>.

Alberta Learning Information Service (2012). *Alberta Occupational Profiles: Gas Pipeline Operators and Maintenance Workers*. <http://alis.alberta.ca/occinfo/Content/RequestAction.asp?aspAction=GetHTMLProfile&format=html&OCCPRO_ID=71001708>.

Angevine, Gerry, and Miguel Cervantes (2011). *Fraser Institute Global Petroleum Survey 2011*. Fraser Institute. <http://www.fraserinstitute.org/uploadedFiles/fraser-ca/Content/research-news/research/publications/global-petroleum-survey-2011.pdf>.

Angevine Economic Consulting Ltd. (2005). *The Economic Impacts of Constructing an Energy Pipeline. A Special Report Prepared for the Canadian Energy Pipeline Association* (May).

BC Government (2009). *First Nations to Join KSL Pipeline Project*. News release (April 8). <http://www.marketwire.com/press-release/Government-of-British-Columbia-First-Nations-to-Join-KSL-Pipeline-Project-972537.htm>.

BC Ministry of Aboriginal Rights and Reconciliation (2011). *B.C. Treaty Negotiations*. <http://www.gov.bc.ca/arr/treaty/negotiating/default.html>.

BC Ministry of Energy, Mines and Petroleum Resources (2010). *British Columbia Natural Gas and Petroleum*. Government of British Columbia.

BC Ministry of Energy, Mines and Petroleum Resources (2011a). *Shale Gas*. Government of British Columbia. <http://www.em.gov.bc.ca/OG/oilandgas/petroleumgeology/ShaleGas/Pages/default.aspx>.

BC Ministry of Energy, Mines and Petroleum Resources (2011b). *Production and Distribution of Natural Gas in B.C.* Government of British Columbia. <http://www.empr.gov.bc.ca/OG/oilandgas/statistics/Pages/MonthlyStatistics.aspx>.

BC Ministry of Energy, Mines and Petroleum Resources (2012). *British Columbia's Oil and Gas Resources—Quick Reference*. A fact sheet with definitions provided in response to a special request from the Fraser Institute.

BC Ministry of Environment (2011). *Code of Practice for the Discharge of Produced Water from Coalbed Gas Operations*. Government of British Columbia. <http://www.env.gov.bc.ca/epd/industrial/regs/codes/coalbed/>.

Billard, Rebecca (2011). *Natural Gas Pipeline Project to Benefit 15 B.C. First Nations*. News release (April 6). First Nations in BC. <http://fnbc.info/natural-gas-pipeline-project-benefit-15-bc-first-nations>.

British Columbia Oil and Gas Commission (2011). *Hydrocarbon and By-product Reserves in British Columbia.* December 14. <http://www.bcogc.ca/document.aspx?documentID=1204&type=.pdf>.

British Petroleum (2011). *BP Statistical Review of World Energy (June).* British Petroleum Corporation.

Canadian Energy Pipeline Association (2011). *Pipeline Safety*. <http://www.cepa.com/wp-content/uploads/2011/06/CEPA_Safety_v4_LR.pdf>.

Canadian Energy Pipeline Association (2012). *Natural Gas Pipeline Significant Failure Statistics*. Provided in response to a special request from the Fraser Institute.

Canada Pension Plan Investment Board (2012). *Listings of Public Equity: Holdings of Canadian and Foreign Companies*. <http://www.cppib.ca/files/F2012_-_YE/Publicly-Traded_Equity_Holdings_-_CDN_-_March_31_2012_-_Eng.pdf and http://www.cppib.ca/files/F2012_-_YE/Publicly-Traded_Equity_Holdings_-_FGN_-_March_31_2012_-_Eng.pdf>.

Carrier Sekani Tribal Council (2006). *An Assessment of the Impacts of the Proposed Enbridge Gateway Pipeline on the Carrier Sekani First Nations* (May). <http://www.cstc.bc.ca/downloads/Oil%20&%20Gas/AIUS%20COMPLETE%20FINAL%20inc.%20maps.pdf>.

Chis, Timur (2007). Pipeline Leak Detection Techniques. *Annals, Computer Science Series* 5, 1: 25–34. <http://anale-informatica.tibiscus.ro/download/lucrari/5-1-03-Chis.pdf>.

Enbridge Northern Gateway Project Joint Review Panel (2012). *Request to Make an Oral Statement*. Public Registry. <https://www.neb-one.gc.ca/ll-eng/livelink.exe?func=ll&objId=624799&objAction=browse&sort=name>.

Environment Canada (2011). *Canada's Emissions Trends* (July). <http://www.ec.gc.ca/Publications/E197D5E7-1AE3-4A06-B4FC-CB74EAAAA60F%5CCanadasEmissionsTrends.pdf>.

Environment Canada (2012). *Canada's Greenhouse Gas Emissions*. <http://www.ec.gc.ca/ges-ghg/default.asp?lang=En&n=1357A041-1>, as at June 21, 2012.

Environmental Leader (2011, May 31). World GHG Emissions Hit Record Levels. <http://www.environmentalleader.com/2011/05/31/world-ghg-emissions-hit-record-level/>.

Government of Canada (2012). An Act to Implement Certain Provisions of the Budget Tabled in Parliament on March 29, 2012 and Other Measures (Jobs, Growth and Long-term Prosperity Act). Bill C-38, June 2012. <http://www.parl.gc.ca/HousePublications/Publication.aspx?Docid=5697420&file=4>.

Hamilton, Gordon (2012, June 15). Apache Discovers Huge Gas Reservoir. *Postmedia News*, reported in the *Calgary Herald*. <http://www.investorvillage.com/mbthread.asp?mb=4288&tid=11827381&showall=1>, as of September 28, 2012.

Healing, Dan (2012, October 2). Contracts Pose Threat to Liquefied Gas Export Plans. *Calgary Herald*. <http://www.calgaryherald.com/business/Contracts+pose+threat+liquefied+export+plans/7333340/story.html>.

Healing, Dan (2012, September 10). BG Group Inks Pipeline Deal for LNG Terminal. Calgary Herald. September 10. <http://www.calgaryherald.com/business/Group+inks+pipeline+deal+terminal/7219132/story.html>

Hightower et al. (2004). *Guidance on Risk Analysis and Safety Implications of a Large Liquefied Natural Gas (LNG) Spill over Water*. Sandia Report SAND2004-6258. Sandia National Laboratories. <http://www.fossil.energy.gov/programs/oilgas/storage/lng/sandia_lng_1204.pdf>.

IHS Global Insight (2009). *The Contributions of the Natural Gas Industry to the Canadian National and Provincial Economies*. Final Report. Prepared for America's Natural Gas Alliance (December)

Interstate Natural Gas Association of America (2011). *Safety: Every Step of the Way*. <http://www.cepa.com/wp-content/uploads/2011/06/INGAA-Pipeline-Safety.pdf>.

Isaac, Thomas, and Anthony Knox (2010). *Canadian Aboriginal Law: Creating Certainty in Resource Development*. McCarthy Tetrault LLP. <http://www.mccarthy.ca/pubs/Resource_development.pdf>.

Jaccard, Marc, and Brad Griffin (2010). *Shale Gas and Climate Targets: Can They Be Reconciled?* School of Resource and Environmental Management, Simon Fraser University. <http://pics.uvic.ca/sites/default/files/uploads/publications/WP_Shale_Gas_and_Climate_Targets_August2010.pdf>.

Kitimat LNG (2010). *Canadian Natural Gas Is Going Global*. Presentation to the National Energy Board (March). <http://www.neb.gc.ca/clf-nsi/rnrgynfmtn/nrgyrprt/nrgyftr/cnslttnrnd4/prsnttn/alfred_sorenson.pdf>.

Kitimat LNG (2011). *Canada, BC, Join Haisla Nation and Kitimat LNG Partners in Marking Project Go-Ahead*. <http://mediacenter.kitimatlngfacility.com/Mediacenter/view_press_release.aspx?PressRelease.ItemID=2807>.

LNG Canada (2012). *Project Overview*. <http://lngcanada.ca/our-business/project-overview/>, as of June 12, 2012

National Energy Board (1998). *Key Documents Related to the Board's Framework for Light-handed Regulation*. June 1998. <https://www.neb-one.gc.ca/ll-eng/livelink.exe/fetch/2000/90465/92833/92844/586917/93538/93772/1998-06-01_Reasons_For_Decision_RHW-1-98.pdf?nodeid=93776&vernum=0>.

National Energy Board (2006). *British Columbia's Ultimate Potential for Conventional Natural Gas.* (March). BC Ministry of Energy, Mines and Petroleum Resources and National Energy Board.

National Energy Board (2009). *Understanding Canadian Shale Gas*. Energy Brief (November). <http://www.neb.gc.ca/clf-nsi/rnrgynfmtn/nrgyrprt/ntrlgs/prmrndrstndngshlgs2009/prmrndrstndngshlgs2009nrgbrf-eng.pdf>.

National Energy Board (2010). *Marketable Natural Gas Production in Canada*. National Energy Board.

National Energy Board (2011a). *Ultimate Potential for Unconventional Natural Gas in Northeastern British Columbia's Horn River Basin* (May). National Energy Board.

National Energy Board (2011b). *Canada's Energy Future: Energy Supply and Demand Projections to 2035* (November). National Energy Board.

National Energy Board (2011c). *Self-imposed Service Standards*. <http://www.neb-one.gc.ca/clf-nsi/rthnb/whwrndrgvrnnc/nbsrvcstndrd/nbsrvcstndrd-eng.html#s1>.

National Energy Board (2011d). *Reasons for Decision – KM LNG Operating General Partnership* (GH-1-2011). October. <https://www.neb-one.gc.ca/ll-eng/livelink.exe/fetch/2000/90466/94153/552726/657379/657474/735753/728336/A2F3D2_-_RfD_GH-1-2011_KM_LNG.pdf?nodeid=728337&vernum=0>.

National Energy Board (2012). *Reasons for Decision – BC LNG Export Co-operative LLC* (GH-003-2011). February. <https://www.neb-one.gc.ca/ll-eng/livelink.exe/fetch/2000/90466/94153/552726/674445/674203/787318/787451/A2L8I2_-_BC_LNG_Export_Co-operative_LLC-_GH-003-2011_Reasons_for_Decision.pdf?nodeid=787452&vernum=0>.

NaturalGas.org (2011). *Unconventional Natural Gas Resources*. Available at: http://www.naturalgas.org/overview/unconvent_ng_resource.asp

Natural Resources Canada (2012). *Responsible Resource Development Plan*. April 17 <http://actionplan.gc.ca/eng/feature.asp?pageId=446>.

Penty, Rebecca (2011, November 21). Pipelines Face Fight from B.C. First Nations. *Calgary Herald*. <http://www.canada.com/business/Pipelines+face+fight+from+First+Nations/5737519/story.html>.

PFC Energy (2012). *LNG Markets Study*. [Appendix C to the application by LNG Canada to the National Energy Board.] June. <https://www.neb-one.gc.ca/ll-eng/livelink.exe/fetch/2000/90466/94153/552726/834773/834774/834279/A2V3I3_-_Appendix_C_-PFC_Energy_-_LNG_Markets_Study.pdf?nodeid=834352&vernum=0>.

Poten and Partners (2010). *2015-2035 LNG Market Assessment Outlook for the Kitimat LNG Terminal* (October). Poten and Partners.

Progress Energy (2012). *Petronas to Acquire Progress Energy*. Media release (June 28). <http://www.progressenergy.com/petronas-to-acquire-progress-energy>.

Shah, Rajiv (2011, May 24). LNG Terminals to Dot Gujarat Coastline. *The Times of India*: <http://articles.timesofindia.indiatimes.com/2011-05-24/ahmedabad/29577504_1_lng-terminals-gujarat-state-petroleum-corporation-gas-terminals>.

Shell (2012). *Shell and Partners Announce LNG Project in Canada*. News release (May 15). <http://www.shell.com/home/content/media/news_and_media_releases/2012/lng_canada_15052012.html>.

Spectra Energy (2011). Application Pursuant to Subsection 12(1)(b) of the National Energy Board Act. August 5, 2011, Page 7. <https://www.neb-one.gc.ca/ll-eng/livelink.exe/fetch/2000/90465/92833/92844/677741/706190/705850/A2C0Q7_-_Application_pursuant_to_subsection_12(1)(b)_of_the_National_Energy_Board_Act.pdf?nodeid=705939&vernum=0>.

Tertzakian, Peter (2011, October 17). Load up the LNG Camels. *Calgary Herald*: <http://blogs.calgaryherald.com/2011/10/17/load-up-the-lng-camels/>.

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

US Energy Information Administration [US EIA] (2011a). *International Energy Outlook 2011*. September. <http://www.eia.gov/forecasts/ieo/>.

US Energy Information Administration [US EIA] (2011b). Monthly Cushing OK WTI Spot Price FOB. <http://www.eia.gov/dnav/pet/hist/LeafHandler.ashx?n=pet&s=rwtc&f=m>.

US Energy Information Administration [US EIA] (2011c). Monthly Henry Hub Gulf Coast Natural Gas Spot Price. <http://www.eia.gov/dnav/ng/hist/rngwhhdM.htm>.

US Energy Information Administration [US EIA] (2012a). *Annual Energy Outlook 2012*. United States Department of Energy. <http://www.eia.gov/forecasts/aeo/pdf/0383(2012).pdf>.

US Energy Information Administration [US EIA] (2012b). *Effects of Increased Natural Gas Exports on Domestic Energy Markets* As requested by the Office of Fossil Energy. <http://www.eia.gov/analysis/requests/fe/pdf/fe_lng.pdf>, as at February 13, 2012.

About the authors

Gerry Angevine

Gerry Angevine is Senior Economist in the Fraser Institute's Global Resource Centre. Dr Angevine has been President of AECL, an energy economics consulting firm, since 1999, and was a Managing Consultant with Navigant Consulting Ltd. from 2001 to 2004. He was President, CEO, and a Director of the Canadian Energy Research Institute from 1979 to 1999. Prior to that, he worked as an economist at the Canadian Imperial Bank of Commerce and the Bank of Canada.

Mr Angevine has advised the Alberta Department of Energy and testified before the National Energy Board as an expert witness. He joined the Fraser Institute in July 2006 and launched the global petroleum survey in 2007. He has also written analyses of Ontario's 2007 Integrated Power System Plan and Alberta's electric transmission policy. More recently, he has led the Institute's North American energy strategy research program.

Mr Angevine has A.M. and Ph.D. degrees in Economics from the University of Michigan, an M.A. in Economics from Dalhousie University, and a B.Com. from Mount Allison University.

Vanadis Oviedo

Vanadis Oviedo was formerly an Energy Analyst in the Fraser Institute's Centre for Global Resource Studies, where she was engaged in research for this and other publications of the Institute. She holds a Bachelor in Arts in Economics from Andres Bello Catholic University in Venezuela and a Master of Science in Sustainable Energy Development from the University of Calgary. Ms. Oviedo joined the Institute in August 2011 as an intern after working for the Alberta Department of Energy as a Junior Energy Market Analyst. Since mid-June of this year, at which point her contribution to the paper had been completed, she has been working as Program Assistant for the Fraser Basin Council in Vancouver.

Publishing information

Distribution

These publications are available from <http://www.fraserinstitute.org> in Portable Document Format (PDF) and can be read with Adobe Acrobat® 7 or Adobe Reader®, versions 7 or later. Adobe Reader® X, the most recent version, is available free of charge from Adobe Systems Inc. at <http://get.adobe.com/reader/>. Readers who have trouble viewing or printing our PDF files using applications from other manufacturers (e.g., Apple's Preview) should use Reader® or Acrobat®.

Ordering publications

For information about ordering the printed publications of the Fraser Institute, please contact the publications coordinator:

- e-mail: sales@fraserinstitute.org
- telephone: 604.688.0221 ext. 580 or, toll free, 1.800.665.3558 ext. 580
- fax: 604.688.8539.

Media

For media enquiries, please contact our Communications Department:

- 604.714.4582
- e-mail: communications@fraserinstitute.org.

Copyright

Date of issue

July 2012

ISSN

ISSN 1918-8323 (Online)

Citation

Angevine, Gerry, and Vanadis Oviedo (2012). *Laying the Groundwork for BC LNG Exports to Asia*. Fraser Institute. <http://www.fraserinstitute.org>.

Editing, typesetting, and design
Lindsey Thomas Martin

Cover design
Bill Ray

Cover images
© Carabay, Bigstock® ("LNG tanker")
© Boroda, Bigstock® ("installation of a gas pipeline")
© Roverto, Bigstock® ("gas processing industry")

Supporting the Fraser Institute

To learn how to support the Fraser Institute, please contact

- Development Department, Fraser Institute
  Fourth Floor, 1770 Burrard Street
  Vancouver, British Columbia, V6J 3G7 Canada
- telephone, toll-free: 1.800.665.3558 ext. 586
- e-mail: development@fraserinstitute.org

Lifetime patrons

For their long-standing and valuable support contributing to the success of the Fraser Institute, the following people have been recognized and inducted as Lifetime Patrons of the Fraser Institute.

Sonja Bata	Serge Darkazanli	Fred Mannix
Charles Barlow	John Dobson	Jack Pirie
Ev Berg	Raymond Heung	Con Riley
Art Grunder	Bill Korol	Catherine Windels
Jim Chaplin	Bill Mackness	

Purpose, funding, & independence

The Fraser Institute provides a useful public service. We report objective information about the economic and social effects of current public policies, and we offer evidence-based research and education about policy options that can improve the quality of life.

The Institute is a non-profit organization. Our activities are funded by charitable donations, unrestricted grants, ticket sales, and sponsorships from events, the licensing of products for public distribution, and the sale of publications.

All research is subject to rigorous review by external experts, and is conducted and published separately from the Institute's Board of Trustees and its donors.

The opinions expressed by the authors are those of the individuals themselves, and do not necessarily reflect those of the Institute, its Board of Trustees, its donors and supporters, or its staff. This publication in no way implies that the Fraser Institute, its trustees, or staff are in favour of, or oppose the passage of, any bill; or that they support or oppose any particular political party or candidate.

As a healthy part of public discussion among fellow citizens who desire to improve the lives of people through better public policy, the Institute welcomes evidence-focused scrutiny of the research we publish, including verification of data sources, replication of analytical methods, and intelligent debate about the practical effects of policy recommendations.

About the Fraser Institute

Our vision is a free and prosperous world where individuals benefit from greater choice, competitive markets, and personal responsibility. Our mission is to measure, study, and communicate the impact of competitive markets and government interventions on the welfare of individuals.

Founded in 1974, we are an independent Canadian research and educational organization with locations throughout North America and international partners in over 85 countries. Our work is financed by tax-deductible contributions from thousands of individuals, organizations, and foundations. In order to protect its independence, the Institute does not accept grants from government or contracts for research.

Nous envisageons un monde libre et prospère, où chaque personne bénéficie d'un plus grand choix, de marchés concurrentiels et de responsabilités individuelles. Notre mission consiste à mesurer, à étudier et à communiquer l'effet des marchés concurrentiels et des interventions gouvernementales sur le bien-être des individus.

Peer review—validating the accuracy of our research

The Fraser Institute maintains a rigorous peer review process for its research. New research, major research projects, and substantively modified research conducted by the Fraser Institute are reviewed by experts with a recognized expertise in the topic area being addressed. Whenever possible, external review is a blind process. Updates to previously reviewed research or new editions of previously reviewed research are not reviewed unless the update includes substantive or material changes in the methodology.

The review process is overseen by the directors of the Institute's research departments who are responsible for ensuring all research published by the Institute passes through the appropriate peer review. If a dispute about the recommendations of the reviewers should arise during the Institute's peer review process, the Institute has an Editorial Advisory Board, a panel of scholars from Canada, the United States, and Europe to whom it can turn for help in resolving the dispute.

Editorial Advisory Board