FUELING CHANGE

UPSTREAM IMPLICATIONS OF THE B.C. LNG SECTOR

Phase 1: Identifying B.C. LNG Export-Induced Natural Gas Extraction Scenarios for FNFN Territory

March 2014

Authored by Alistair MacDonald,
The Firelight Group Research Cooperative

Commissioned by Fort Nelson First Nation

FUELING CHANGE: UPSTREAM IMPLICATIONS OF THE B.C. LNG SECTOR

Phase 1: Identifying B.C. LNG Export-Induced Natural Gas
Extraction Scenarios for FNFN Territory

March 2014

Authored by Alistair MacDonald, The Firelight Group Research Cooperative

Commissioned by Fort Nelson First Nation

ACKNOWLEDGEMENTS

The findings herein are those of the author, based primarily on review of publicly available information. Nonetheless, support was provided by several parties to this work. Thanks go to FNFN Lands Department, especially Robert Conception for GIS support, to reviewers of draft material, and to Dave Thompson of The Firelight Group for peer review of this document.

2026 Kennay-Yah Road
RR1 Mile 295 Alaska Highway
Fort Nelson, B.C. V0C 1R0

T: 250-774-6313
F: 250-774-6317
E: reception.lands@fnnation.ca
www.fortnelsonfirstnation.org

253 – 560 Johnson St., Victoria B.C. V8W 3C6
T: 250.590.9017
E: info@thefirelightgroup.com
www.thefirelightgroup.com

Contents

FIGURES

TABLES

PHASE 1

Executive Summary

EXTREMELY LARGE NATURAL GAS RESOURCES are located in shale deposits underlying Fort Nelson First Nation (FNFN or the Nation) territory in northeastern B.C. FNFN shale gas basins include the Horn River Basin, the Cordova Embayment, and the Liard Basin. In recent years, these resources have been unlocked due to hydraulic fracturing (fracking) and horizontal drilling technologies, bringing rapid change to FNFN territory.

Fort Nelson First Nation is very concerned about what the future may hold for extraction of gas in the Nation's territory. Of particular concern is the development of a B.C. liquefied natural gas export sector.

FNFN is very concerned about what the future may hold for extraction of gas in the Nation's territory. Of particular concern is the development of a B.C. liquefied natural gas (LNG) export sector, the groundwork for which is being laid in the form of NEB export licences, commercial agreements, and environmental assessments to establish pipelines and LNG export facilities on British Columbia's northwest coast. Increasingly, it appears that LNG exports to Asia will be a – perhaps *the* – major driver of future gas growth in FNFN territory.

To date, minimal work has been done to evaluate the upstream implications of fueling these proposed pipelines and LNG export facilities with natural gas, despite the massive amounts of gas feedstock required. Given these information deficits, FNFN commissioned Alistair MacDonald of The Firelight Group Research Cooperative (the author) to conduct a two-part study to look at how the development of an LNG export sector in B.C. can affect the Nation's lands and rights. This study represents the first attempt by any party to look at potential effects on the air, water, land, wildlife and Treaty rights holders in FNFN territory – or any First Nations territory – of different LNG export scenarios. It does so first by estimating a realistic range of the amount of gas extraction from FNFN territory that will be induced by the fledgling B.C. LNG export sector (this Phase 1 report), and then estimating some of the potential effects (physical and otherwise) on FNFN territory of this range of LNG-induced gas extraction scenarios (the separate Phase 2 report).

In Phase 1, the author reviewed existing secondary data on the global LNG sector, current B.C. LNG export proposals, and the comparative current and likely future role of FNFN shale gas basins in the Western Canada Sedimentary Basin (WCSB) natural gas production system, to develop a range of realistic scenarios of:

- The amount of B.C. LNG exports over its first (proposed) 20 years of operation; and
- The proportion of LNG feedstock that will come from FNFN territory.

The report then combines these two sets of inputs in a matrix that identifies a range of the amount of gas from FNFN territory that will be used to fuel the B.C. LNG export market.

This Phase 1 study develops a range of realistic scenarios of how much natural gas will be extracted from FNFN territory to feed the B.C. LNG export sector over its first 20 years.

Scenarios are used to establish a range of realistic possibilities, not specific predictions. The author used a wide range of data sources to triangulate how much B.C. LNG export capacity is likely to be developed. The inputs for the analysis included B.C. government goals and forecasts, proposals to date for LNG facilities and associated pipelines, and industry analyst estimates of potential B.C. LNG export sector growth.

Subsequently, five methods were used to help estimate what proportion of the natural gas used to fuel the B.C. LNG export sector will come from FNFN territory:

1. Current FNFN gas production as a proportion of current WCSB totals;
2. FNFN gas-in-place as a proportion of WCSB totals;
3. Industry, government and analysts' future estimates of basin-by-basin production;
4. Discussion of factors affecting basins' competitive advantages in the supply of LNG; and
5. Vertical linkages of current FNFN territory gas tenure holders to proposed LNG facilities.

Findings include the following:

1. B.C. LNG exports will average between 37.5 and 82 million tonnes per annum (mtpa), starting about 2018, and lasting over an initial 20 year period. This is equivalent to between 4.9 and 10.7 billion cubic feet per day (Bcf/day) of natural gas feedstock.
2. Between 10 and 25 per cent of the gas for B.C. export facilities will come from FNFN territory. The gas plays in the area are immature and are likely to contain somewhere between 13 and 25 per cent of the recoverable gas resources in the WCSB. Industry estimates indicate that gas extraction from FNFN territory may in the future grow to between 19 to 30 per cent of WCSB production. Despite some competitive disadvantages versus

the more developed Montney Basin, these factors and the level of vertical integration of a variety of companies with tenure in FNFN territory to the fledgling B.C. LNG sector indicates strong potential for LNG-induced gas extraction growth from FNFN territory.

3. Combining the two criteria above, as illustrated in the table below, development of a B.C. LNG export sector will induce between 490 million and 2.68 billion cubic feet per day in gas extraction from shale gas basins in FNFN territory.

FNFN LNG-induced gas extraction matrix

LNG demand (2018–2038 average)/ FNFN production proportion	10% FNFN gas	25% FNFN gas
Low scenario: 4.9 Bcf/day	0.49 Bcf/day	1.23 Bcf/day
High scenario: 10.7 Bcf/day	1.07 Bcf/day	2.68 Bcf/day

A wide range of data sources was used to triangulate a broad range of potential outcomes. Inputs for the analysis included B.C. government goals and forecasts, proposals to date for LNG facilities and associated pipelines, and industry analyst estimates of potential B.C. LNG export sector growth.

Most scenarios within this range would see significant increases in the amount of gas produced from FNFN territory above historic and current numbers. The lowest LNG demand scenario in FNFN territory would be 160 per cent more than 2012 gas production levels from FNFN territory of 0.28 Bcf/day. At the high end of the realistic scenarios, that number jumps to an almost 10-fold difference.

These numbers equate to between 178 and 978 Bcf/year of natural gas extracted from FNFN territory as a result of the B.C. LNG export sector. When converted to LNG production, the amount equates to between 3.75 and 20.5 mtpa. This volume ranges from an amount sufficient to support a small portion of a single medium-sized LNG facility to enough gas to support a large LNG facility or two medium-sized LNG facilities. Over a 20 year period, the amount equates to between 3.56 Tcf and 19.5 Tcf of LNG-induced additional gas extraction from FNFN territory.

The author purposefully erred on the side of conservative estimates where possible in this scenario development exercise. The likely 10 per cent additional required gas for power generation or transportation in the LNG export production system is not included in the calculations. Nor is the additional 10 to 19 per cent of "shrinkage" (product losses in processing) between raw and sales gas, or potential "induced exploration effects," wherein new demand for LNG may see expansion of supply by an amount greater than the LNG requirement (e.g., through development of economies of scale that reduce the costs of production and make FNFN gas more competitive in North American markets). Given this built-in conservatism, it is possible that the actual outcomes in terms of LNG-induced gas extraction from FNFN territory may exceed the identified high end estimated within this study. In contrast, it is extremely unlikely that the actual outcome will be lower than the low end estimate.

The point of this study was consider all of the wide range of future outcomes. The overarching finding is that ***change is coming to FNFN territory as a result of LNG***. This study represents only a first exploratory step in the task of estimating the upstream impacts of LNG in B.C. This report's findings indicate the need for further detailed work on scenarios of change linking upstream gas development to the B.C. LNG export sector. Conduct of additional scenario analyses to refine those identified in this preliminary study is part of this required further work. It is critical for industry and government to build scenario analyses into planning associated with the fledgling B.C. LNG export sector.

The overarching finding is that change is coming to Fort Nelson First Nation territory as a result of LNG.

Armed with a set of realistic scenarios of how much growth in gas production from FNFN territory would be caused by development of a B.C. LNG export sector, Phase 2 of this study will focus on estimating how this newly induced demand will affect FNFN lands and resources.

ACRONYMS USED IN THIS REPORT

Bcfd or Bcf/day	Billion cubic feet per day
Bcf/mi^2 or Bcf/km^2	Billion cubic feet of natural gas per square mile or square kilometre
B.C.	British Columbia
BC EAO or EAO	British Columbia Environmental Assessment Office
BC MEM	British Columbia Ministry of Energy and Mines
BC OGC or OGC	British Columbia Oil and Gas Commission
CEAA	Canadian Environmental Assessment Agency
CO_2	Carbon dioxide
EA	Environmental assessment
EUR	Estimated ultimate recovery (sometimes called expected ultimate recovery)
FNFN	Fort Nelson First Nation
Gj	Gigajoules
Ha	Hectares
HRB	Horn River Basin
IGU	International Gas Union
km	Kilometres
Km^2	Square kilometres
LNG	Liquefied natural gas
Mmcf	Million cubic feet
Mmcf/d	Million cubic feet/day
mtpa	Million tonnes per annum
MW	Megawatts
NEB	National Energy Board
NGLs	Natural gas liquids
NWT	Northwest Territories
Tcf	Trillion cubic feet
Tcf/yr	Trillion cubic feet/year
TCPL	TransCanada Pipelines Ltd.
U.S.	United States
U.S. EIA	United State Energy Information Administration
WCSB	Western Canada Sedimentary Basin

CONVERSIONS USED IN THIS REPORT[1]

Natural gas in its gaseous form is typically measured in volumetric terms, either in millions, billions or trillions of cubic feet (Mmcf, Bcf, Tcf) or cubic metres (Mmcm or Bcm). The following equivalence calculation can be used to convert between the two:

1 cubic metre = 35.3 cubic feet

LNG, however, is typically measured in millions (metric) tonnes per annum (mtpa). The following conversion factors are used in this report, as per Ernst and Young (2013a):

1 million tonnes of LNG = 1.36 Bcm of natural gas or about 48 Bcf of natural gas.

The conversion table below was used to convert gas to LNG in this report and vice versa. Note that while gas equivalents are measured by day and year, LNG is measured only by year/annum.

	Bcf/day (NG)	Tcf/year (NG)	Bcm/day (NG)	Bcm/year (NG)	Mtpa (LNG) =
1 Bcf/day (NG) =	1	0.365	0.028	10.22	7.66
1 Tcf/year (NG) =	2.74	1	0.076	28	21
1 Bcm/day (NG) =	35.3	12.88	1	365	270
1 Bcm/year (NG) =	0.097	0.35	0.003	1	0.74
1 Mtpa (LNG) =	0.13	.0047	0.004	1.46	1

Area conversions applicable to this report are as follows:

1 square mile (mi^2) = 2.59 square kilometres (km^2)

1 acre = 0.40 hectares

1 Conversion sources include KM LNG (2010), Ernst & Young (2013a), and British Gas Conversation Factors, accessed at bp.com/conversionfactors.jsp

SECTION 1

Introduction

1.1 STUDY OVERVIEW

Fort Nelson First Nation (FNFN or the Nation) is a traditional hunting/gathering society that has lived for countless generations in the boreal forest of northeastern British Columbia. A Dené/Cree linguistic group with roughly 800 band members living on and off reserve, FNFN members practice constitutionally and Treaty 8 protected rights to the lands and resources required to maintain their way of life on the land.

"Each [B.C. LNG] proposal would see a dramatic increase in fracking in the northeastern region of B.C. and require massive liquefaction plants to be built on the coast."
– Crist (2013, 10)

Over the last decade, there have been rapid increases in natural gas development in FNFN territory, largely due to hydraulic fracturing of the area's three shale gas basins. These activities have impacted the traditional territory of the FNFN, through seismic line cutting, construction of access roads and well pads, water withdrawals and wastewater disposal, increased noise and pollution in area lands, airs and waters. Wildlife habitat has been bisected, creating a fragmented ecosystem where moose, caribou, furbearers and other animals relied upon for Treaty rights practices are subject to many new pressures.

FNFN is very concerned about what the future may hold for extraction of gas in the Nation's traditional lands. Of particular concern is the development of a B.C. liquefied natural gas (LNG) export sector, the groundwork for which is being laid in the form of NEB export licences, commercial agreements, and environmental assessments to establish pipelines and export facilities on British Columbia's northwest coast. Increasingly, it appears that LNG exports will be a major driver of future gas growth in northeastern British Columbia, including within FNFN territory. Estimates of future upstream (gas extraction) growth due to LNG are only starting to come out now, but one of the first (National Bank 2013) suggests that even four B.C. LNG facilities (more than 10 have been proposed to date) could see 6500 new wells drilled in the Western Canada Sedimentary Basin (WCSB) to provide gas feedstock to these facilities.

FNFN territory encompasses some of the largest natural gas reserves in the WCSB and some of the largest proven shale gas resources the world. FNFN basins include the Horn River Basin, the Cordova Embayment, the Liard Basin, and a small northern portion of the Montney

Basin (see Figure 1 in Section 2). As an increasing number of LNG export facilities are being proposed for the B.C. coast, and multiple pipelines are planned to provide dedicated links for these LNG facilities into northeast B.C. and its abundant gas reserves, it is clear that industry and the B.C. government intend to facilitate the development of these reserves as feedstock for the LNG export sector. Even conservative estimates of LNG quantities needed to sustain these export facilities would result in a significant increase in "upstream activities" – gas production in northeastern B.C. and in FNFN territory, almost all of it via hydraulic fracturing, or "fracking," of shale and tight gas deposits.

The B.C. government has been studying and marketing the economic benefits of LNG,[2] but has collected or disseminated very little information on its environmental implications.[3] Minimal work has been done to evaluate the upstream implications of fueling these proposed pipelines and export facilities with natural gas.

Given these information deficits, FNFN commissioned Alistair MacDonald of The Firelight Group Research Cooperative (the author) to conduct a two-phase study to look at how the development of an LNG export sector in B.C. may affect the Nation's lands and rights. This study represents the first attempt by any party to look at potential effects on the air, water, land, wildlife and Treaty rights holders in FNFN territory – or *any* First Nations territory – of different LNG export scenarios. It does so by estimating the amount of gas demand likely induced by the fledgling B.C. LNG export sector out of the shale deposits in FNFN territory, and then estimating some of the potential effects (physical and otherwise) of these different shale gas production scenarios.

Phase 1 develops a range of realistic scenarios of how much natural gas will be extracted from FNFN territory to feed the B.C. LNG export sector over its first 20 years.

Phase 2 uses the Phase 1 development scenarios to examine the associated environmental effects of LNG development on FNFN territory, including impacts to the ground, the water, the air, the plants and animals existing within the territory, as well as select social, economic and cultural impacts.

This report summarizes findings from Phase 1 of the study. The report reviews existing secondary data on the global LNG sector, current B.C. LNG export proposals, and the comparative current and likely future role of FNFN gas basins in the B.C. natural gas production system, to develop a series of realistic scenarios (ranges) for:

- The amount of B.C. LNG exports over its first (proposed) 20 years of operation; and
- The proportion of LNG feedstock that will come from FNFN territory.

It then combines these two sets of inputs in a matrix that identifies a defensible range of the amount of gas from FNFN territory used to fuel the B.C. LNG export market.

It is important to note that this study represents only a first exploratory step in the task of estimating the upstream impacts of LNG in B.C. The findings detailed in this report are not conclusive, but are rather indicative of the need for further more detailed work on scenarios of change linking upstream gas development in northeastern B.C. to the B.C. LNG export sector.

2 The B.C. government has made very public efforts to estimate, based on different scenarios of 82 to 120 million tonnes per year of LNG exports, what the economic benefits might look like for British Columbia (Ernst and Young 2013b); Grant Thornton 2013a; 2013b).

3 For example, a recent government study looking at the greenhouse gas implications of LNG market development in B.C. has not been released by the government at the time writing of this report (theglobeandmail.com/news/british-columbia/secret-report-measures-impact-of-lng-on-bc-environment/article15334449/).

1.2 REPORT STRUCTURE

This report is structured as follows:

- Section 2 outlines the geographic scope of the study.
- Section 3 describes the methods used, assumptions and limitations of Phase 1 of the study.
- Section 4 provides an overview of two key elements of this study, the global LNG sector and the North American natural gas supply sector.
- Sections 5, 6 and 7 provide the findings, triangulated from a variety of secondary research materials, that the author used to develop scenarios of:
    - Section 5 – the size of B.C.'s LNG export sector;
    - Section 6 – the proportion of B.C. LNG gas supply that will be extracted from within FNFN territory; and
    - Section 7 – total LNG-induced gas extraction scenarios for FNFN territory, combining the first two factors.
- Section 8 provides a summary of the results of Phase 1, some recommendations for further work, and introduces the next steps associated with Phase 2 (effects estimation using the FNFN LNG-induced gas extraction scenarios).

SECTION 2

Setting the Scene: Shale Gas Basins and Activity in FNFN Territory

2.1 CURRENT NATURAL GAS ACTIVITY IN FNFN TERRITORY

As shown in Figure 1, FNFN's core territory[4] covers the entire B.C. boundaries of three natural gas basins – the Liard Basin to the west, Horn River Basin in the central, and the Cordova Embayment in the northeast. The Horn River Basin has seen the bulk of exploration, development and production activity to date, but all three are highly prospective and immature gas basins, meaning their gas resource remain almost completely intact.

All are shale basins containing large amounts of natural gas[5] which, until recently, was thought to be unreachable due to the depth and structure of these formations.[6] The rise of hydraulic fracturing and horizontal directional drilling has overcome this limitation in recent years, and shale gas deposits are likely to become Canada's primary source of natural gas for decades to come. A fourth major reserve – the Montney Formation, which covers large portions of northwestern Alberta and the Peace Region in B.C. – also stretches into the southern end of FNFN core traditional territory. Altogether, these gas basins cover more than half of FNFN core traditional territory.[7] Important FNFN natural gas basins are described in more detail in Section 6.1, within the context of the larger Western Canada Sedimentary Basin (WCSB).

B.C.'s natural gas sector underwent a boom during the past decade. Between 1999 and 2008 alone, investment in the sector went from $1.7 billion to over $9 billion per annum (OnPoint Consulting 2010). As shown in the "before and after" images of the years 2006 and 2013 in Figure 2, industrial development within FNFN core territory has accelerated rapidly in the last decade with the rise of shale gas basin exploration and development.

4 FNFN defines its core territory as mapped in Figure 1, showing the areas most often used by FNFN in its traditional territory. As River people, FNFN members' activities tend to radiate outwards from rivers, especially the Fort Nelson, Snake and Liard Rivers, and currently from their primary residential reserve near Fort Nelson.

5 The "dry" natural gas found in all three shale basins is primarily methane or CH_4.

6 $(S\&T)^2$ Consultants (2010, 19) indicate that "shales are less permeable than concrete, so the natural gas cannot easily move through the rock and into a well."

7 Horn River and Liard Basins and the Cordova Embayment cover 36,690 km^2 – 45.8 per cent of the total FNFN core territory. The northern reach of the Montney adds to this total.

Figure 1: FNFN core traditional territory, showing major shale gas basins

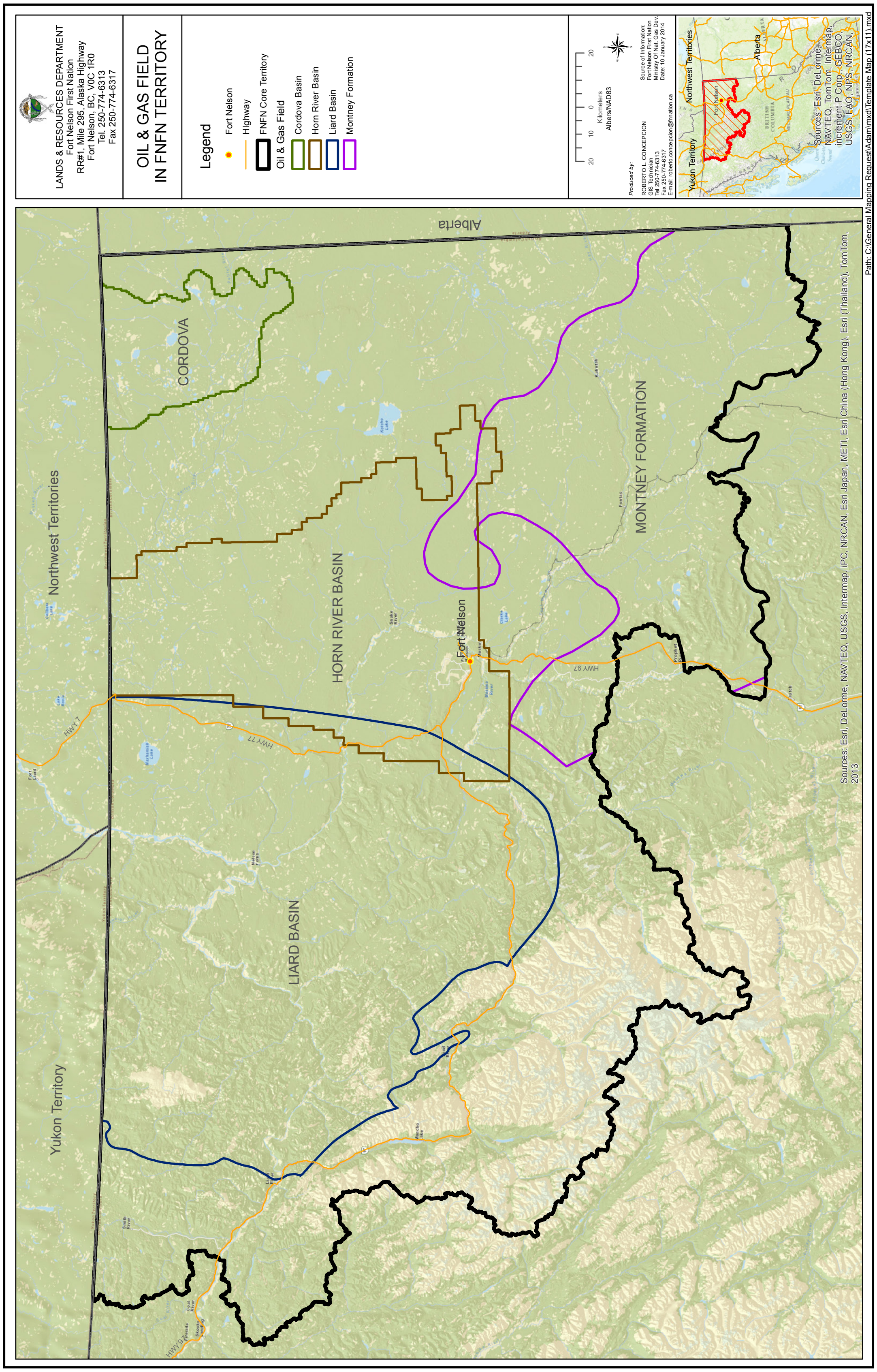
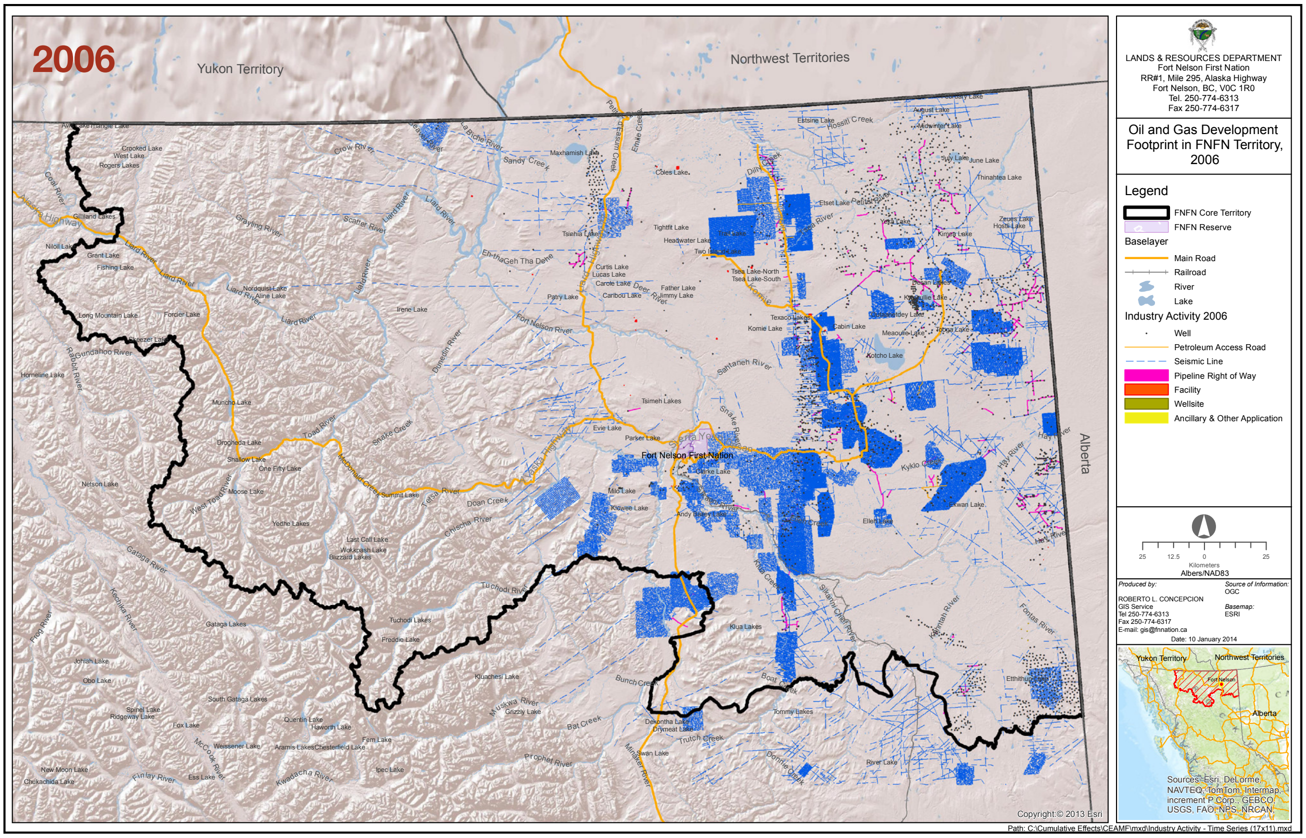
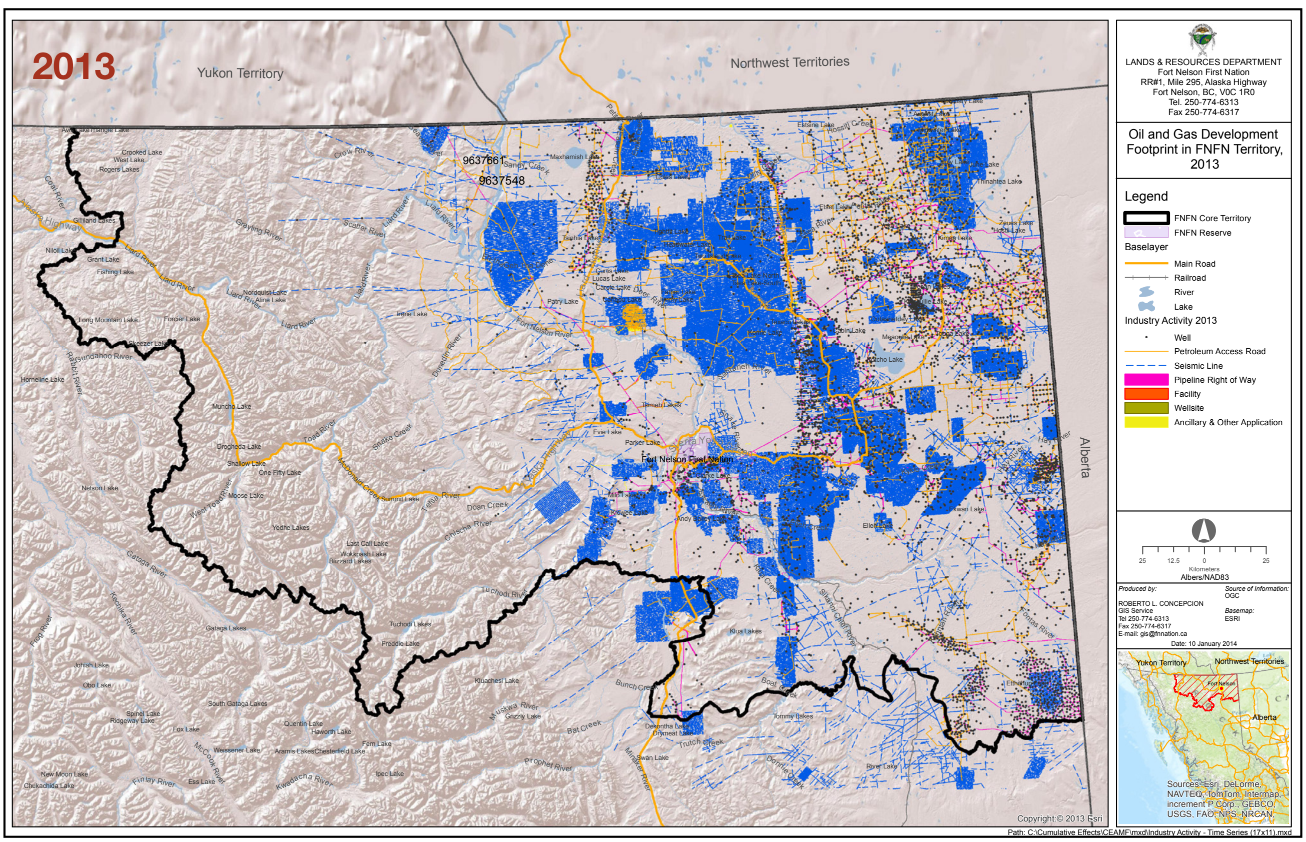


Figure 2: Oil and gas development and associated infrastructure on FNFN traditional lands, 2006 and 2013





How Hydraulic Fracturing Works

The process of hydraulic fracturing (fracking) is required to recover certain kinds of gas deposits, like shale and tight sands. In FNFN territory, the deposits are largely held in shale, a non-porous and fine-grained sedimentary rock (B.C. OGC, 2010). The fracking process is illustrated in the figure below. To access gas reserves in these shale formations, several steps are taken:

- A horizontal well must be drilled. A horizontal well increases the length of contact with the shale gas formation over that of a conventional vertical well.
- A liquid mixture is injected to create pressure and induce stress in the rock ("stimulate") and create fissures and cracks. These cracks increase the permeability of the formation to increase the flow rate of gas into the well. The liquid is composed largely of water and sand, but chemical modifiers are added to facilitate fracturing (Gregory et al., 2011). These chemicals may include gels, foam, hydrochloric acid, biocides, or other fluids (King, 2013). In addition to high water requirements, each fracked well may require up to 4,000 tons of proppants, and up to 200,000 litres of chemicals (International Energy Agency 2013; 2012).
- After the fracturing activity, the pressure is decreased and gas flows from fissures into the well. In addition, some reports estimate between 10 and 40 per cent of injected fluid returns to the surface as "flowback" (Gregory et al., 2011) – others report between 50 and 90 per cent (B.C. OGC, 2011).

Increasingly, multiple wells from a single well pad and multiple fractures per well are being used in FNFN territory.

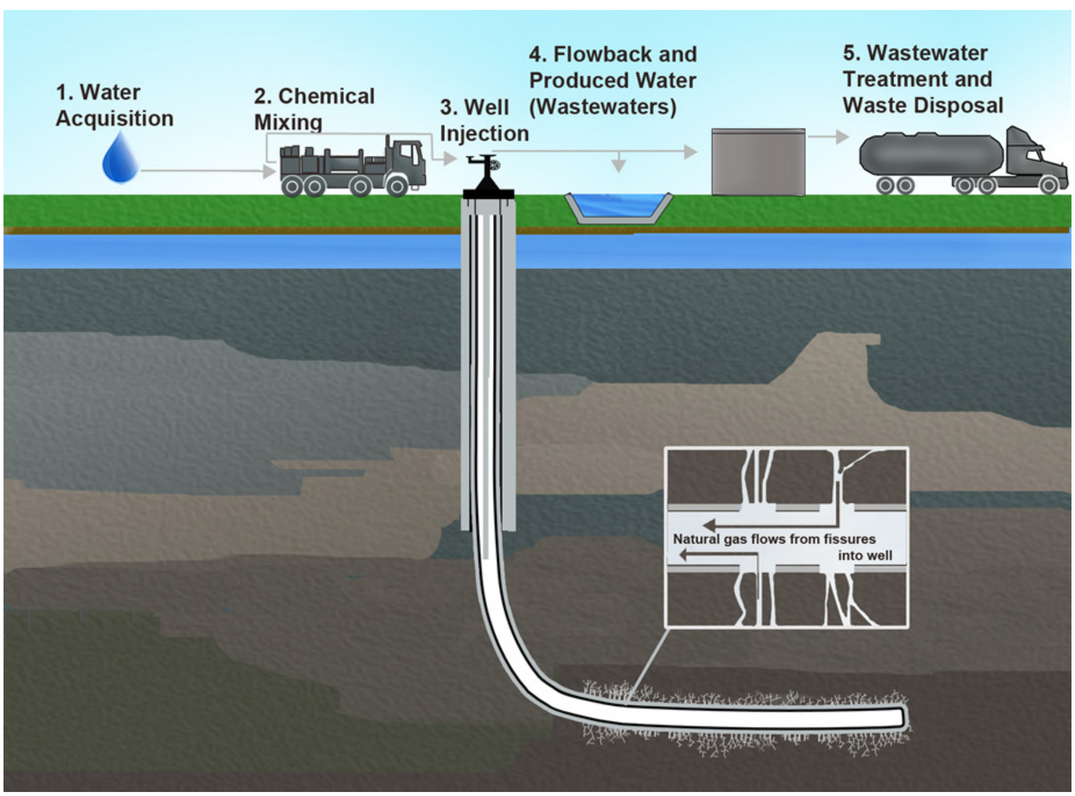


Image source: Fross and Lyle (2013)

Hydraulic fracturing to extract gas from the Horn River Basin has been the major driver of this development. Impacts such as linear disturbances (roads, seismic lines and pipelines) and large areal disturbances (e.g., clearing for gas plants, water storage, and well pads) have increased dramatically over the last decade. Increased access leads to habitat fragmentation, particularly for large ungulates such as woodland caribou and moose, increased predation risk, and increased access into the area for non-Aboriginal harvesters.

Hydraulic fracturing also requires vast amounts of water.[8] As a result, water withdrawals from FNFN territory have also increased rapidly, both in amounts and sources, over the last decade.

Table 1 summarizes shale gas-related activity associated with the Horn River Basin, the Liard Basin and the Cordova Embayment as of 2012.

Table 1: Summary of shale gas-related activity in Horn River Basin, Liard Basin and Cordova Embayment

	Horn River Basin	Liard Basin	Cordova Embayment
% of land base tenured to gas interests by 2012	63.5%	18.4%	44.6%
Linear disturbance 2002–2012 (density on tenure)	59,915 km (6.84 km/km^2)	7,137 km (1.07 km/km^2)	11,531 km (5.93 km/km^2)
Areal disturbance on tenure (250m buffer on lines), 2012	71% of tenured lands	33% of tenured lands	73% of tenured lands
Gas wells drilled 2007–2012	537	39	53
Well pads constructed 2007–2012	255	32	22
Production rate per day	381 Mmcf/d (2011) 245 Mmcf/d (2012)	No data 21 Mmcf/d (2012)	No data 15 Mmcf/d (2012)

Source: B.C. OGC data, through published materials (see references section) and materials available to the FNFN Lands Department's GIS team through B.C. OCG's shape file database, www.bcogc.ca/public-zone/gis-data

Between 2007 and 2012 alone, 307 well pads were developed and 627 wells drilled in the three basins within FNFN territory. During this time period, the shift from conventional vertical wells to horizontal shale gas fracking has been almost complete. According to B.C. OGC (2010), as of 2009/10, 140 of 164 wells targeted shale gas, a huge increase from three of 88 in 2005/6. All indications are that the role of conventional gas deposits in FNFN territory production (and in the WCSB in general) is on a long-term and precipitous decline (see Section 4.3.2 for further discussion).

Phase 2 of this study uses a detailed examination of changes to date in the three basins to inform projections of likely future impacts in a range of LNG demand scenarios.

8 This is particularly the case in FNFN territory. Johnson (2009, 39) suggests that "Water demands in the Horn River Basin are expected to escalate dramatically as the regional shale gas exploration and development accelerates," and even that estimate was based on 7,000 to 30,000 m^3 per well, much lower than the estimates for Horn River Basin, which Johnson (2012) tabulated at between 34,700 and 81,000 m^3 per well, between ten and 15 times more than that used in Montney.

SECTION 3

Phase 1 Study Methods

Note: Phase 2 methods are discussed in that separate report.

3.1 STUDY APPROACH

Phase 1 of this Study establishes a series of scenarios (see *Why use scenarios?* on the following page) to explore how an LNG export sector may plausibly develop in British Columbia and what the implications of this would be for gas extraction from FNFN territory.

Specifically, Phase 1 uses a wide range of available secondary published data to explore two key topics: total B.C. LNG capacity development and the proportion of natural gas extracted from basins in FNFN territory.

A range of realistic scenarios for each are then brought together to identify a range of potential LNG-induced gas extraction scenarios for FNFN territory.

The three steps used in Phase 1 of the study are described below.

Data sources used to triangulate and capture the high and low LNG export scenarios include government estimates, facility proposals to date, and estimates by industry analysts.

Step 1: Develop high and low B.C. LNG export scenarios (Section 5)

A wide variety of available secondary data sources were used to identify a range of potential B.C. LNG export scenarios. These export scenarios by extension define the amount of natural gas that must be extracted to fuel this export sector. The sources of information used to triangulate and capture the high and low LNG export scenarios include government estimates, facility proposals to date, and estimates by industry analysts.

Why use scenarios?

There are a large number of variables that can affect the amount of gas produced on a basin-by-basin basis. They include a variety of difficult to predict production costs issues, changing comparative advantages of different basins, and end user demand that is extremely difficult to predict, among many other considerations. This makes for a wide range of future gas production predictions. For example, in its forecasting of future Montney basin gas production, BC Hydro (in Steve Davis and Associates Ltd. 2011) identifies 11 different future production forecasts, some of which vary five to six-fold in size.

In situations like this where a large number of variables increase the uncertainty of confidently predicting a single specific outcome, scenarios are a useful mechanism for exploring the range of potential outcomes over a period of time. By examining a series of scenarios based on triangulation of available sources (e.g., establishing low and high ends of potential LNG export capacity and the proportion of WCSB gas extraction that may come from FNFN traditional lands), it is possible to discuss the risks and rewards associated with a range of possible futures.

Greig and Duinker (2007) describe how scenario development can be used as a means to bound the discussion about how development could proceed:

> *Scenario development as an aid to planning is focused on developing alternative visions of the future. By working with scenarios of quite different futures, the analytical focus is shifted away from trying to estimate what is most likely to occur toward questions of what are the consequences and most appropriate responses under different circumstances. Scenarios usually serve one of two functions: one is risk management, where scenarios enable strategies and decisions to be tested against possible futures, with the other is creativity and sparking new ideas. Scenario-based work is most powerful when several alternative scenarios are created and analyzed, and each should provide significant contrast from the others.*

As Greig and Duinker (2007) note, taking a scenario-based approach is a good way to deal with the inherent uncertainty involved in any futuring exercise, by putting the focus on exploring the consequences of alternative futures, rather than unrealistically trying to make a single specific estimate.

Step 2: Identify a range of proportions of how much B.C. LNG-induced gas will come from FNFN territory (Section 6)

Four primary basins underlay FNFN traditional territory: Horn River, Liard, Cordova Embayment and Montney.[9] Step 2 of this study uses a variety of factors to triangulate the potential proportion of gas required to fuel B.C.'s LNG demand that would come from the three basins (Horn River, Liard and Cordova Embayment) that are primarily or exclusively located within FNFN territory.

Sources of information for this triangulation include current production levels from FNFN territory, ultimate recoverable supply estimates by government and industry, estimated future production rates, analysis of the competitive advantages of different gas basins in the WCSB, and examination of ties between gas companies with tenure in FNFN territory to specific LNG proposals. Some of the assessment is quantitative in nature; other elements (such as consideration of comparative advantages on a basin-by-basin basis) are more qualitative.

Table 2 identifies examples of secondary data types used in Steps 1 and 2.

Table 2: Example secondary data sources used in the Phase 1 study

Step	Description	Example source materials
Step 1: B.C. LNG export scenarios	Government estimates of LNG export scenarios (Section 5.1)	B.C LNG Strategy, economic effects modeling by Ernst & Young (2013b) and Grant Thornton (2013b)
	Industry LNG proposals to date (Section 5.2)	NEB Export Licence Applications and supporting documents, CEAA and BCEAO environmental assessment public records, general media
	Estimates from industry analysts (Section 5.3)	Ziff Energy Group (2013a; 2013b); Fraser Institute (2012)
Step 2: Per cent of LNG gas requirements likely to be extracted from FNFN shale basins	Current production proportion (Section 6.2)	NEB, B.C. OGC, industry analysts
	Gas in place proportion (reserves) (Section 6.3)	NEB, B.C. OGC, company estimates
	Future predictions of basin-by-basin production (Section 6.4)	Industry, government and industry analysts
	Comparative advantages of different WCSB basins (Section 6.5)	Industry analysts, corporate presentations, government studies, general media
	Links of FNFN tenure holders to specific LNG proposals (Section 6.6)	NEB export licence applications, industry analysts, press releases

9 Only the northern reaches of the Montney basin extend into FNFN territory (see Figure 1). However, given that the Montney reaches into active gas exploration areas in the general Fontas area south of Fort Nelson and is located in slightly closer proximity to both the LNG export market and existing pipeline infrastructure capacity, there is every reason to believe extractive activities in that portion of the Montney in FNFN territory will fuel some of B.C.'s LNG sector. Leaving it out of the study parameters here was part of a conscious decision to err on the side of conservative estimates.

Step 3: Develop a range of LNG-induced gas extraction scenarios for FNFN territory, based on a matrix combining the results of scenarios from steps 1 and 2 (Section 7)

In Step 3, the ranges identified in steps 1 and 2 are brought together in an LNG-induced gas extraction matrix specific to FNFN territory. The FNFN LNG-induced gas extraction matrix combines the range of potential total B.C. LNG demand levels and range of potential extraction proportions from FNFN gas basins to develop a range of numerical estimates of potential LNG export-induced extraction from FNFN lands.

A 20 year time span between 2018 and 2038 has been chosen as the boundary for analysis. The reasons for this are as follows:

1. The author used conservative timelines in light of uncertainty about future outcomes. In general, the shorter the temporal scope of assessment, the greater the likelihood of predictive accuracy.
2. NEB export licence applications (e.g., KM LNG 2010) are for between 20 and 25 years.
3. The majority of the proposed LNG projects, especially larger ones like Pacific Northwest LNG, LNG Canada and Prince Rupert LNG, have estimated startup dates around or later than 2018.

There will obviously be a ramp-up period for each LNG project that proceeds and, by extension, for sector-wide LNG production. This study does not estimate change over time (e.g. year-over-year LNG export levels). The ranges generated should be treated as annual averages throughout the 20 year time span.

3.2 STUDY LIMITATIONS

A number of limitations to the methodology used in this preliminary study must be recognized:

- The pace of change in the gas sector has been and will likely continue to be rapid. The whole picture can change quickly, making it difficult to confidently estimate future activity levels and location. For example, within a couple of years in the late 2000s, technological change toward unconventional gas sources increased resources several fold in the North American gas market. The future is equally uncertain.
- Secondary data are relied upon exclusively to develop the range of potential outcomes for each set of scenarios. The data from secondary sources, including predictions by government agencies and industry analysts, are adequate to predict a wide range of B.C. LNG export production levels moving forward. However, they cannot be used to estimate what number is most likely.
- Similarly, it is impossible to predict with certainty what proportion of the gas will be extracted from FNFN territory and its three primary gas basins based solely on available public information. The best information about key factors that will have a major impact on production in FNFN lands (e.g. comparative potential production costs by basin) are largely not in the realm of freely available public information and thus beyond this study's scope to examine.

- LNG proposals are changing rapidly and new projects are rapidly proliferating as large international companies seek to lock up NEB export licenses and secure sources of upstream supply for their respective LNG facilities. These constant changes mean that the "top end" of LNG export demand may yet increase.[10]

- Exploration and evaluation work is an ongoing practice in different gas plays, and there are multiple updates put forward in any given year. Increasing technology and exploration activities refine information, almost always pushing total resource numbers upwards. Thus, it is a reasonable expectation that revised aggregate resource estimates will increase, possibly significantly, over time. This may shift FNFN basins' proportions up or down.

To overcome these limitations and generate defensible results, the analysis herein uses the following principles, tools and assumptions:

- As wide as possible a range of data sources was used to triangulate a broad range of potential outcomes.

- Scenarios are used to establish a wide range of possibilities, not specific predictions or forecasts. This report does not attribute any probability that specific outcomes will or will not occur in the future.

- Where possible, the analysis errs on the side of conservative estimates (e.g., LNG export sector and FNFN production contribution will be lower, not higher, than the data suggests). The exclusion of Montney from FNFN territory and exclusion of "shrinkage" or gas for process power demands, which may reduce gas demand estimates by 25 per cent or more,[11] are examples.

The Role of Power Demand in the LNG Sector

Crist (2013, 10) suggests "Liquefying natural gas is one of the most energy-intensive industrial processes today. Just one LNG facility could use approximately 1,200 megawatts [MW] of power." Estimates for the amount of electricity that proposed LNG projects would need range from a low of 45 MW for Douglas Channel LNG to 1200 MW for LNG Canada. As pointed out by Environmental Law Centre (2013, 60), "in comparison, the proposed Site C hydro project would produce 900 MW."

U.S. EIA (2012, 2) suggests that "additional natural gas consumed during the liquefaction process" constitute approximately 10 per cent of total gas required. Neither this 10 per cent increase in gas requirements nor any calculation of other process losses or shrinkage of raw gas during removal of impurities (which may be from 12 to 19 per cent in FNFN gas basins, primarily consisting of CO_2), are considered in Firelight's calculations in this study.

10 For example, NEB received three new LNG related export license applications in October and November 2013 alone.

11 "Shrinkage" refers to the amount of material extracted from a gas well that is lost to the environment or during processing from raw to sales gas. Gas in FNFN territory tends to be very high in carbon dioxide (CO_2) that must be removed, and thus typically has a higher degree of shrinkage than other WCSB gas formations.

- The analysis assumes that all new demand will be driven by the LNG export market; there has been no focus on the domestic market. In parallel all new supply predicted is assumed to be fueling LNG, not the domestic or North American market. Current production, all of which goes into the North American market, is assumed to be the same moving forward and the implications of combined domestic and LNG demand considered only in Figure 10 in Section 7. This domestic demand stagnation assumption is likely unrealistic and conservative, given estimated future growth in Canadian domestic demand (e.g. Ziff Energy Group 2013a).

- The analysis assumes that 100 per cent of the gas extracted to fuel the B.C. LNG export market will come from the WCSB, which currently supplies some 98 per cent of Canada's gas production.[12] Eastern Canadian LNG projects (there are two at this time) are not included.[13]

- The current wide price differential between North American and Asian gas, critical to the development of a viable B.C. LNG sector, is assumed to remain in place (See *Price Differentials in North American and Asian Natural Gas Markets* on page 23).

Despite its limitations, the findings herein are realistic within the confines of currently available public data. This study presents an important first step in understanding potential impacts of LNG on upstream gas production regions, by establishing a range of scenarios for LNG-induced gas extraction from FNFN territory. To the author's knowledge, the scenarios developed are the first realistic effort by any party to publicly identify these upstream implications in specific First Nations territories.

12 Other studies, such as Mirski and Coad (2013, 9), identify the possibility that B.C. will supply all the gas – "With 87.4 million tonnes of liquefaction capacity proposed, there is a potential requirement for B.C. natural gas production to rise from its 2011 level of 1.4 Tcf/year to 5.6 Tcf/year over just a decade" (the 4.4 Tcf/yr increase is equivalent to 11.5 Bcf/day or the predicted 87–88 mtpa of LNG). Given that B.C. only currently produces about 20 per cent of Canada's gas, the author did not adopt this assumption.

13 Ziff Energy Group (2013c, 9) suggests that "connecting gas resources outside of Western Canada is generally not viable due to the high cost of developing and transporting these resources to market and the availability of lower cost gas resources already connected to North American markets."

SECTION 4

Global LNG Demand and Canadian Gas Supply

4.1 INTRODUCTION

Natural gas is becoming an increasingly important contributor to global energy supply. Currently at 21 per cent of the global primary energy mix, behind only oil and coal, natural gas has the highest projected growth rate of any fossil fuel between 2008 and 2036 (International Energy Agency 2013). The rise of a global LNG market, along with the newfound ability to extract unconventional gas deposits of massive size,[14] are among the factors making natural gas a prime mover in the global economy. And Canada is well situated to enter into this global market, with the fifth largest technically recoverable shale gas resource in the world after the U.S., China, Argentina and Algeria (Advanced Resources International Inc. 2013).

This section examines changing global, North American, and Canadian gas market circumstances, especially due to changes in LNG demand and unconventional gas supply.

"The success of the [B.C.] LNG-for-export initiative will be very closely linked to the success of northeast shale gas development. The LNG plants need assured long-term supplies of gas and firm long-term contracts with growing Asian markets" – Steve Davis and Associates Ltd. (2011, 40)

4.2 LNG MARKET DEMAND

Liquefied natural gas, or LNG, is a liquid form of natural gas that allows for transportation of the fuel across long distances. It is produced by super-cooling methane to -162°C, which causes the gas to liquefy to 1/600th of its normal volume. The initial commercial production of LNG occurred in 1941. In 1959, the world's first LNG tanker, *The Methane Pioneer*, carried LNG from Louisiana to the United Kingdom, demonstrating that large quantities of LNG could be transported safely across the ocean.[15] Today, specially designed massive

14 The term "unconventional" encompasses gas resources previously considered difficult to economically extract, such as shale and tight sands deposits and coalbed methane.

15 beg.utexas.edu/energyecon/lng/LNG_introduction_06.phpl

Gas Sector Terminology

Only a fraction of the original gas located in the basin is eventually produced from shale formations. This "recovery factor," along with the process of discovery, development, and extraction of the gas, means that there is a variety of terminology associated with gas estimates that must be understood, as the difference between risk and unrisked gas, resources and reserves, and gas in place and currently marketable gas, can be very high. The terms are listed here in general order from least to most certain "knowability," and from largest to smallest amounts of estimated gas.

ORIGINAL GAS IN PLACE (OR GAS IN PLACE) – The volume of raw natural gas estimated to exist originally in naturally occurring accumulations, prior to production.

RESOURCES – Estimated quantities of gas likely to be potentially recoverable from undiscovered accumulations by future development. **CONTINGENT RESOURCES** are estimated quantities from known accumulations that are not yet considered mature enough for commercial development. **PROSPECTIVE RESOURCES** are estimated quantities potentially recoverable from undiscovered accumulations.

RESERVES – Estimated remaining quantities of natural gas anticipated to be technically and economically recoverable from known accumulations, as of a given date. Proven reserves are defined at having a 90 per cent certainty of recoverability; probable reserves have a 50 per cent certainty of recoverability.

RECOVERABLE GAS – The volume of gas in place that can be extracted from an accumulation.

ESTIMATED ULTIMATE RECOVERY (EUR) – Sometimes called "expected ultimate recovery," total volume of gas recoverable under current technology and present and anticipated economic conditions, usually estimated by well averages in an accumulation or for the entire accumulation (a play or basin).

MARKETABLE GAS – The volume of gas deemed economically recoverable with applicable technology, minus losses attributable to processing and fueling surface production facilities.

The terms **"RISKED AND UNRISKED GAS"** are also sometimes used. **UNRISKED GAS IN PLACE** is that which have already been developed by drilling and thus have a very reasonable certainty of being produced. **RISKED GAS IN PLACE** is a measure of contingent and prospective resources, and the designation is typically used to characterize poorly developed or undeveloped gas fields. Unrisked gas is always a lower but more certain amount.

Sources included B.C. OGC (2013a), B.C. MEM and NEB (2011).

double-hulled LNG ships are used to transport LNG overseas to regasification systems in increasingly huge quantities.[16] With the growth of LNG transportation, the gas market is transitioning from regional to global. LNG trade represented around nine per cent of global gas demand in 2012.

4.2.1 Global LNG Demand

The global LNG market has grown significantly over the last decade, and is predicted to increase by an additional 50 per cent between 2012 and 2020. According to the International Gas Union (2011), from 2006 to 2011 the volume of LNG traded grew from 159.1 to 241.5 million tonnes per annum (mtpa), a 52 per cent increase. Macquarie Research (2012a) estimates global LNG demand forecast at 405 mtpa by 2020, an annual growth rate of 6 per cent.[17] The list of proposed LNG projects is growing at an even more rapid rate. Indeed, 150 mtpa of newly proposed capacity has been announced over the past 18 months alone, equivalent to more than 50 per cent of current global demand (Macquarie Research 2012b).

By far the largest global exporter of LNG is Qatar, at one quarter of global LNG liquefaction capacity in 2013 (75 mtpa). Other major players in global LNG exports include Malaysia (25.0 mtpa), Indonesia (21.4 mtpa), Australia (19.2 mtpa) and Nigeria (12.6 mtpa), according to the International Gas Union (2011). The export industry in Australia is growing faster than any of the other countries, but is facing rapidly increasing costs affecting some projects' viability (Macquarie Research 2012b).

Global LNG demand is in part driven by the perception that natural gas is a "cleaner" energy source than conventional oil. This perception is certainly not shared by everyone (e.g., Howarth et al. 2011). The Phase 2 report for this study identifies a variety of environmental and other concerns associated with the natural gas sector.

What *is* certain is that global LNG demand has risen and is expected to continue growing rapidly. Since 2006, many countries have started to import LNG, including Argentina, Brazil, Chile, China, Kuwait, and the United Arab Emirates. The 2011 tsunami and nuclear crisis in Japan drove demand for natural gas in that country alone up by 8.2 mtpa to a world leading 79 million tonnes (International Gas Union 2011). Given environmental concerns with oil and coal as power sources, as well as with nuclear energy as an alternate source, the LNG market is almost certain to continue growing at a rapid rate. If China and India escalate their use of natural gas and are unable to source the majority of it internally, this too may be a substantial growth impetus for LNG exports (Antunes et al. 2012). Bentek Energy (2013) suggests that global LNG demand is expected to grow 39 per cent between 2013–2018, faster than projected 27 per cent increase in global gas supply.[18] The International Gas Union (2011, 4) predicted that "demand for LNG for the next 5 years is expected to remain strong as evidenced by several countries [in Latin America, Southeast Asia and the Middle East] advancing plans to import LNG."

16 The largest LNG carrier, called Q-Max, can transport 264,000 m^3 of LNG (or around 0.15 Bcm or 5.5 Bcf of gas).

17 The International Gas Union (2011) is not as bullish, estimating 366 mtpa by 2020.

18 Not all estimates are as rosy, either in the supply-demand gap for LNG or the strength of B.C.'s position to take advantage of it (e.g., CBC News 2013; Park 2013). Comparative advantages and disadvantages of B.C. as an LNG exporter versus other countries are examined in more detail in Section 5.4 of this report.

4.2.2 North American LNG Market

> *As recently as five years ago, North America was preparing to vastly increase LNG imports as the United States and Canada faced declining conventional production.* – International Gas Union (2013, 35)

As noted by the International Gas Union, the growth of the North American LNG industry has been substantially driven to date by the U.S. import market. With a growing domestic supply of natural gas over the past decade due to rapid shale gas expansion,[19] however, U.S. LNG import requirements have effectively vanished. As of 2011, the U.S. export industry was listed at 0.3 mtpa. However, the U.S. capacity for LNG exports is predicted to grow substantially. Two new facilities have been approved on the Gulf Coast, and some 15 others are proposed, including one in Oregon.[20] Some are former LNG import facilities being re-tooled for exports. Shipping costs to Asian markets are currently an impediment for Gulf Coast facilities, but the proposed expansion of the Panama Canal, due for completion by 2016, will facilitate shipping of LNG from the Gulf of Mexico to global markets (Thomson Reuters 2013). As of 2012, the U.S. has more than 200 mtpa of LNG export capacity proposed, which could translate into more than 28 Bcf/day in gas feedstock. Ernst and Young (2013a) suggest the market is unlikely to need anywhere near that amount.

Currently Canada has only one LNG facility; the Canaport import facility in New Brunswick, which imported 2.4 million tonnes of LNG in 2011 (International Gas Union 2011). Indicative of the recent rapid about turn in the North American LNG sector, this Canadian facility in late 2013 received approval from the NEB to export LNG.[21]

The rise of a fledgling LNG export sector in Canada can be attributed to large reserves and low domestic and North American gas prices, making it an attractive commodity for overseas markets in the Far East (Macquarie Research 2012a). According to Wood Mackenzie (2011), demand for LNG within the Pacific Rim, specifically from China, India, Japan and Korea, is predicted to be strong. Poten & Partners (2010) identified that LNG demand in the Asia Pacific was likely to grow by an average of 2.7 per cent per annum between 2014 and 2035, creating a rising supply-demand gap.

British Columbia is eager to take advantage of this supply-demand gap by expediting the building of pipelines and LNG export facilities to carry WCSB gas to Asia. In 2012, B.C. produced 1.3 Tcf or 3.5 Bcf/day of sales gas and it is expected that B.C. will produce 1.2 Tcf or 3.4 Bcf/day in 2013 (NEB, 2013a). B.C.'s stated total natural gas production goal is more than double current rates at 3 Tcf or 8.7 Bcf/day by 2020 (B.C. Ministry of Energy and Mines 2013). This growth prediction relies heavily on LNG export assumptions. B.C.'s original LNG export goal of 5.9 Bcf/day by 2020, from the provincial LNG Strategy (B.C. Ministry of Energy and Mines no date), even though it represents close to double B.C.'s current gas production rates, has already been dwarfed by NEB export licence applications and a raft of environmental assessments for far higher export capacity (see Section 5.2), as well as the B.C. government's own much higher range of estimates (see Section 5.1).

19 Total North American gas production has grown from 52 Bcf/day in 2005 to over 69 Bcf/day in 2012, largely due to this growth in U.S. shale gas production (International Gas Union 2013).

20 This Jordan Cove project is included in Section 5.2.'s list of LNG projects because its 2013 export licence application indicates a substantial proportion of its gas feedstock would come from the WCSB (Jordan Cove LNG L.P. 2013).

21 cbc.ca/news/canada/new-brunswick/canaport-lng-given-permission-to-export-via-tankers-1.2441102

4.3 GAS DEMAND AND SUPPLY IN CANADA

Total Canadian production of natural gas in 2012 was somewhere between 13 Bcf/day (Ziff Energy Group 2013b) and 14 Bcf/day (NEB 2013a), down five per cent from the previous year and down from 17 Bcf/day in 2005. Some 98 per cent of Canadian gas is currently sourced from the Western Canada Sedimentary Basin (WCSB), a vast sedimentary basin underlying 1,400,000 km^2 of western Canada, including northeastern British Columbia. According to NEB and U.S. Energy Information Administration (U.S. EIA) data, Canada produces 18 to 20 per cent of the total natural gas production in North America, with the U.S. producing the remainder (Priddle 2013b). B.C. gas contributes approximately 25 per cent of Canadian total gas production at 3.5 Bcf/day (Centre for Energy 2013). With no overseas export facilities, the current production is destined exclusively for the domestic or North American market.

Currently, more than half of Canadian production is still exported to the U.S. (+/- 8 Bcf/day in the first four months of 2013 – Priddle 2013b), but this proportion has been declining for several years, "pushed out" by high volume of U.S. shale production. The International Energy Agency (2011, in Linley 2011) estimates that between 2000 and 2006, U.S. shale gas production rose at an average annual rate of 17 per cent, and between 2006 and 2010 this rose to 48 per cent growth per annum. Indeed, much of central Canada's gas supply is now imported from the U.S. (Ziff Energy Group 2013b).

The North American gas market is predicted to continue to grow, reaching approximately 100-105 Bcf/day by 2025 (Priddle 2013b – with Canada at 16-18 Bcf/day) and 119 Bcf/day in 2050 (Ziff Energy Group 2013a, – with Canadian production of 21 Bcf/day).[22] The Conference Board of Canada (Antunes et al. 2012) predicts that demand for Canadian natural gas should double by 2035. The largest drivers of this anticipated growth in *demand* for Canadian gas include electricity generation (including replacement of coal fired plants), bitumen (oil sands) development and LNG exports. The latter two are the potential demand game changers.

4.3.1 Canadian Unconventional Gas Supply

The primary game changer in Canadian gas *supply* is the rise of large and increasingly accessible unconventional gas resources. These resources are becoming critical at the global level. As noted by the International Energy Agency (2013), by 2012 unconventional gas production reached 18 per cent of global production, and shale gas production rates (primarily in the U.S.) have increased 13-fold over the past decade. Shale gas is expected to make up more than 60 per cent of overall North American production by 2035 (Northwest Gas Association 2013).

Advances in shale gas extraction technology have contributed to a doubling of Canada's estimated marketable natural gas resources since 2000. Current known shale gas reserves could supply domestic gas demand for somewhere between 65 and 150 years[23] at Canada's current rate of consumption.

---

22 Ziff Energy Group (2013c) offers a slightly different perspective with Canadian supply at 24 Bcf/day by 2050, and North American total production at 126 Bcf/day by that date.

23 This estimate from the Canadian Society for Unconventional Resources (Heffernan and Dawson 2010) suggests 343 Tcf as the low case and 819 Tcf as the high case for Canada's shale gas resources. These numbers will continue to change as technology and economic conditions influence which reserves can be profitably extracted.

The rapid development of unconventional gas resources in North America, coupled with LNG technology for trans-oceanic movement of natural gas, represents a significant game changer for the global energy sector, the Canadian natural gas industry, and the province of B.C. (Petroleum Human Resources Council of Canada 2013). Western Canada is thought to have high potential to be a global supplier of LNG.

One of the primary likely sources of natural gas for LNG exports from Canada, and North America in general, is shale gas – gas that is tightly bound within shale rock formations and must be extracted using hydraulic fracturing. This type of unconventional gas extraction has only recently becoming economically viable. With the rise of horizontal directional drilling and hydraulic fracturing, they have become a major and rising contributor to the North American and global gas markets. Unconventional gas is predicted to account for nearly half the growth in global gas production by 2035 (IEA 2012), growing to 35 per cent of total natural gas production from 14 per cent in 2010.

North America is forecast to lead global shale gas production over the long term and Canada is positioning itself to become a significant shale gas producer. Shale gas resources account for more than half of the country's gas reserves and have been identified as a significant factor in increasing the country's competitive advantage in energy markets on a global scale (Government of Canada 2013). In fact, production levels for tight and shale gas have more than doubled in a little over a decade (NEB 2013a). Ziff Energy Group (2012; 2013a) predicts that 74 per cent of gas produced in Canada between 2019 and 2044 will be from unconventional sources in Western Canada. The National Energy Board (NEB) (2013b) reports that there has been a "major increase in estimates of Canada's tight and shale gas resources"; and that 92 per cent[24] of gas produced in Canada by 2035 will be unconventional gas. Indeed, B.C. MEM and NEB (2011) identified that the unconventional Horn River shale basin alone has as much remaining recoverable gas potential (78 Tcf) as all of Alberta's remaining conventional gas potential, and estimated that the total remaining conventional gas potential in the WCSB amounts to 119 Tcf, and amount dwarfed by shale gas potential.

4.3.2 WCSB's Transition to an Unconventional Gas Focus

The WCSB is undergoing a rapid shift from conventional to unconventional gas activity. According to the B.C. OGC (2013b), conventional gas reserves are typically found in porous and permeable rock formations, typically less than 20 metres in thickness, with well-defined areal extent. These "pools" are exploited via well pads typically separated by 500 to 1,000 metres, with one vertical well per pad. They were previously the only accessible deposits because their formations have high permeability and require less technology to access and extract (Moniz et al. 2011).

In contrast, unconventional reservoirs include shale gas, tight gas sands, and coal bed methane. They are larger in geographic scale and total resource but "require advanced technology for production and typically yield lower recovery factors than conventional reservoirs" (Moniz et al. 2011, 18), with typical recovery factors to date in the 15 to 30 per cent range.[25] According to the B.C. OGC, "unconventional reservoirs such as

24 From this number, 28 per cent is shale gas, primarily from FNFN basins, and 62 per cent is tight gas, primarily from Montney Basin. Tight sands gas is similar to shale in its low permeability but is generally formed in sandstone or carbonate (OnPoint Consulting 2010).

25 B.C. MEM and NEB (2011) estimated 78 Tcf of marketable gas from 448 Tcf "in place" from the Horn River Basin, approximately 18 to 19 per cent. Oil and Gas Journal (2011) suggests a recovery factor for Horn River Basin may be in the 15 to 25 per cent range. It is worth noting that recovery factors tend to increase with technological improvements during the life of shale plays (NEB 2009).

fine grained sandstones, siltstones and shales are widespread. They occur over large areas and individual formations can reach thicknesses in excess of 300 metres" (B.C. OGC 2013b, 7). These "basins" see typical development patterns as follows:

> *…space drill pads relatively uniformly across the basin on the premise gas is evenly distributed… Drilling is typically continued horizontally when the target formation is reached, extending 2,500 metres or more from the surface location. Unconventional well pads can be widely spaced several kilometres apart and one pad can accommodate 16 wells or more. As a result, less total surface area and fewer wellpads are required to access the same subsurface volume as conventional development."* (B.C. OGC 2013b, 7)

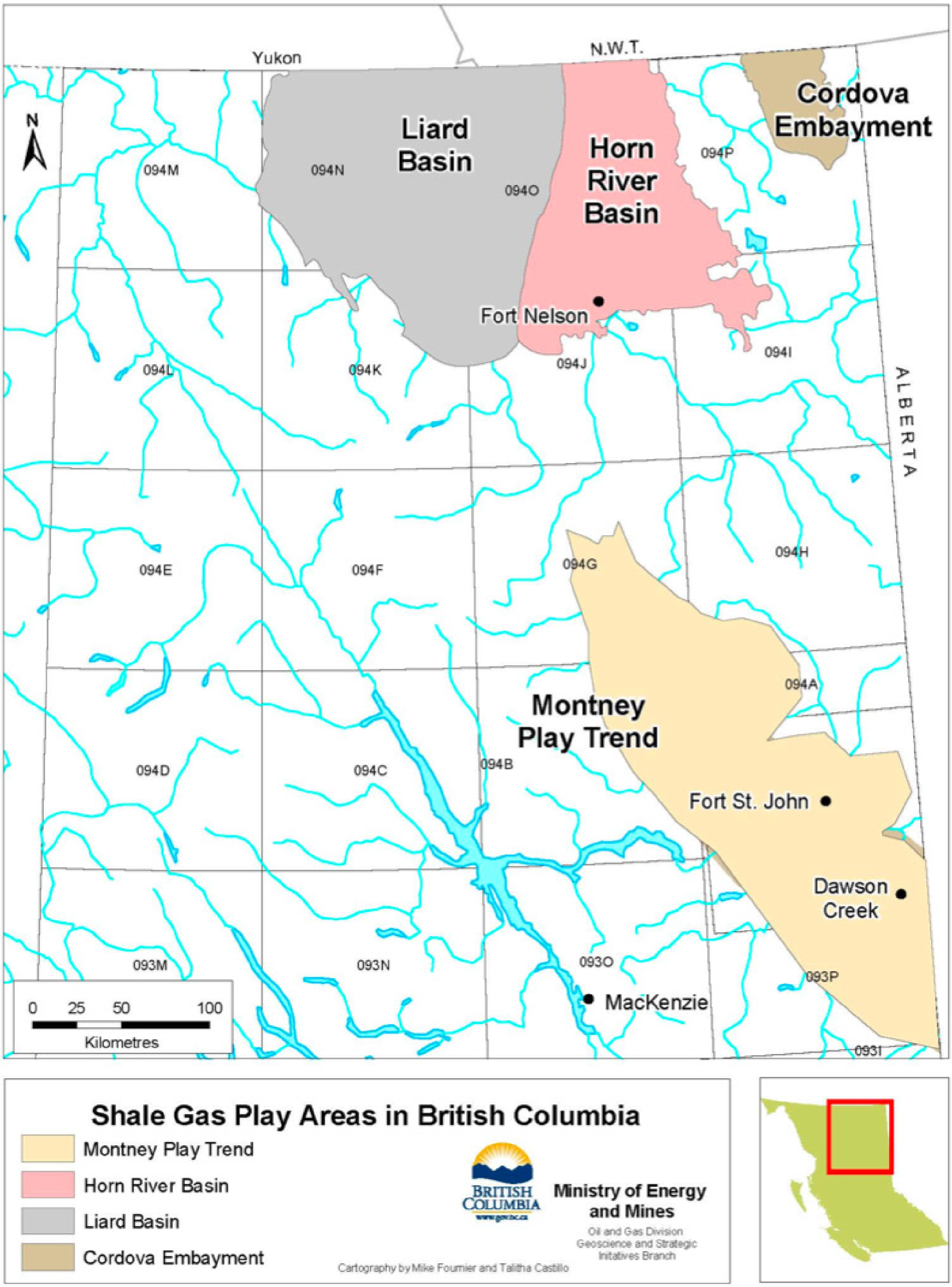
Despite the increased complexity of extracting gas from unconventional basins, these plays are highly attractive for a couple of reasons. First of all, their sheer size (geographic- and gas volume-wise) dwarves that of conventional plays. Secondly, as noted by KM LNG (2010), "The shale play [referring in this case to the Horn River Basin], by its very nature, differs from conventional plays because it has high geological certainty." In other words, the likelihood of drilling a costly and time consuming dry (unsuccessful) well is extremely low in the undifferentiated shale basins. Unconventional gas now provides higher rates of return to investors: "British Columbia's Montney play in particular is one of the best shale plays in North America, while the Horn River Basin is also more competitive than conventional natural gas plays" (OnPoint Consulting 2010, 10). Unconventional technology improvements have also led to strong increases in the initial productivity and estimated ultimate recovery (EUR) per well, especially in FNFN territory (NEB 2013a, Table A2.1; Anderson 2010). Increased production per well reduces the number of wells that need to be developed, improving economies of scale per unit of production. Conventional resources have become laggards, both unprofitable at current prices and declining in available reserves.

Within the WCSB, major unconventional reserves include the Montney Basin and the Horn River Basin, where in combination over 1,400 wells are producing over 2 Bcf/day of gas.[26] B.C.'s contribution to WCSB sales gas production is estimated to continue to rise, from approximately 3.5 Bcf/day of a 13 to 14 Bcf/day WCSB total in 2012 to more than half by 2022 (Northwest Gas Association 2013). Other potentially important shale gas reserves that are as yet largely undeveloped in the WCSB include the Liard Basin and Cordova Embayment in B.C., as well as the Duvernay, Banff, Exshaw and Fernie formations in Alberta.

Section 6.1 examines the proportions of gas-in-place recoverable gas and other characteristics of different WCSB basins and Sections 6.3 through 6.7 digs deeper into factors likely to impact on future gas production on a basin-by-basin level. Figure 3 identifies the extent of key unconventional gas basins within B.C.

26 As of November 2012, based on B.C. OGC data.

Figure 3: Location of key unconventional gas plays in B.C.



Source: B.C. Ministry of Energy and Mines, Oil and Gas Division. (2011). Summary of Shale Gas Activity in Northeast British Columbia 2011. Accessed at empr.gov.bc.ca/OG/OILANDGAS/PETROLEUMGEOLOGY/SHALEGAS/Pages/default.aspx

4.3.3 Looking to the Future: LNG-Induced Gas Extraction from FNFN Territory

As shown in Figure 1, FNFN territory hosts three key shale gas basins: the Horn River and Liard Basins and the Cordova Embayment. Table 1 (Section 2) summarized the current extent of gas tenure and activity within these basins. It shows that as of 2012, more than 60 per cent of the Horn River Basin and 40 per cent of the Cordova Embayment was covered by gas tenures. Liard was lower at 18.4 per cent. Despite the high rate of tenured land, these three basins are currently producing significantly less than their peak potential. This is in part because they are still "immature" but also because Canadian natural gas has been in a recent holding pattern, with minimal drilling activity over the past couple of years as prices in the North American market have dipped to historic lows that did not justify development in northeastern B.C. (NEB 2013a).

"The enormous potential supply from these [North American shale gas] formations has outpaced natural gas demand growth in North America and led to applications to export LNG to overseas markets."
– NEB: 2013a, 3

Given that the substantial increase in gas exploration on FNFN traditional lands has occurred during an average to declining gas market, future growth on FNFN

Price Differentials in North American and Asian Natural Gas Markets

- The price for delivered LNG to Asian markets in December 2013 is reported to be at $17.90 million metric British thermal units (Mmbtu, equivalent to 1000 cubic feet) up from less than $14 Mmbtu the previous year. In an article for the Wall Street Journal, Yep (2013), reported some estimates predict that "LNG is set to surpass the price of crude oil" or as high as $18.30 Mmbtu in January, 2014. This is equivalent to $105/barrel of oil.
- In contrast, the market price for natural gas resources in North America, which was over $10 Mmbtu in 2008, has fallen in recent years at an all-time low of between $2-4 Mmbtu, equivalent to between three and a half and six times lower than the price in Asian LNG markets.
- B.C. OGC (2010, 11) notes that "the biannual average natural gas price shows a positive correlation between the number of applications [in the Horn River Basin] and natural gas prices," using the Henry Hub pricing point for natural gas future contracts traded on the New York Mercantile Exchange. In other words, the higher the sale price for gas, the more activity occurs upstream.
- In the late 2000s, North American market prices softened and by mid–2009 during the recession, North American shale competition created surpluses and "stranding" of high production cost resources in northeast B.C. (U.S. EIA, 2011; Jensen, 2011).
- The current Asian LNG price differential of as much as $15 over North American gas has the potential to release stranded gas resources in FNFN territory. There is also the risk, however, that this price differential shrinks through delinking of Asian gas from oil and associated price corrections due to a variety of sellers coming onstream at the same time (CBC News 2013), along with increases from all-time lows in North American gas prices back into the $5-7 range in the latter part of this decade (Northwest Gas Association 2013; Suttles 2013). The effects of such a potential price convergence is an issue examined in closer detail in Section 5. 4 of this report.

traditional lands has occurred during an average to declining gas market, future growth on FNFN territory will likely be unprecedented in scale when market conditions improve. One of the primary drivers of that growth is likely from the attractive prices and high demand of Asian markets for LNG, especially given declining U.S. imports for Canadian gas since 2007. As the International Gas Union (2011, 49) notes:

> *… an important implication of lower demand for Canadian gas in the U.S. is that new shale gas being developed in western Canada is now more likely to be exported as LNG.*

North American LNG exports to Asia are especially attractive given gas price differentials between the two markets.

As a result of the rapidly changing supply and demand dynamics discussed above, only very recently have two separate potential future scenarios been envisioned for Canadian natural gas production. The first is the "business as usual" production model where WCSB gas remains exclusively distributed within the North American market. This scenario anticipates expansion of Canadian consumption due to oil sands, offset by declining exports to the U.S., mainly due to rapid expansion of U.S. shale gas production crowding Canadian gas out of the U.S. market by shale gas basins such as the Barnett (Texas), Fayetteville (Arkansas) and Marcellus in northeast U.S. (Mason 2011, Entrekin et al. 2011, Linley 2011), with resulting relatively slow growth for the Canadian gas sector (NEB 2013a).

The second, entirely new, scenario includes development of a new LNG export market for Canadian gas alongside continuous North American demand. Forecasts vary depending on a range of factors, but anticipate rapid expansion of the role of LNG exports in total Canadian production. Growth of this secondary market may be critical to the Canadian gas industry. As Ziff Energy Group (2013c, 4) puts it: "[As] Canadian gas [is] pushed out of traditional markets… Canadian gas needs LNG export markets."

Given that this report aims to predict a likely range of LNG-induced gas extraction from FNFN territory, the analysis focuses exclusively on the second demand scenario. Given the degree of expressed interest and advanced investment in LNG export sector development to date in B.C. (see Section 5.2) and reduced competitiveness for Canadian gas in a U.S. market recently saturated by large amounts of shale gas, the development of a B.C. LNG export market is likely inevitable.

There is strong momentum for LNG development in B.C. – and great current governmental and industry pressure to capitalize on this potential. Uncertainty remains about exactly how the development of this industry will play out in B.C. Nonetheless, it is possible to identify a range of potential LNG export sector scenarios and their potential inducement of natural gas extraction from FNFN territory.

Sections 5, 6 and 7 of the report examine potential natural gas development scenarios for the WCSB and FNFN territory, in the first 20 years of an LNG export sector. The results form the basis for Firelight's analysis in Phase 2 of this study of potential impacts to FNFN territory from the development of a B.C. LNG export industry.

SECTION 5

Establishing a Range of B.C. LNG Exports

IT IS CRITICAL FIRST TO ESTABLISH A REALISTIC RANGE of B.C. LNG exports. Firelight used three main types of data to triangulate how much B.C. LNG export capacity is likely to be developed. The inputs for the analysis include:

- B.C. government estimates and forecasts;
- Industry proposals to date for LNG facilities and associated pipelines; and
- Industry analyst estimates of potential B.C. LNG export sector growth.

B.C. government estimates are among the highest and are, according to many industry analysts, unrealistic at the present time. However, the Province's continued reference to these scenarios requires that they be considered in this analysis.

5.1 B.C. GOVERNMENT ESTIMATES

The B.C. government has been a primary booster of LNG export growth. In its 2012 *LNG Strategy* (B.C. Ministry of Energy and Mines, 2012), it set an LNG export goal of 5.9 Bcf/day (equivalent to 45 mtpa). This B.C. government goal has since demonstrably risen, given the inputs to more recent government-funded economic effects studies conducted by Grant Thornton (2013a; 2013b) and Ernst and Young (2013b). Based on the figures provided by the Province for those three studies, the B.C. government is promoting an LNG market ranging from 82 to 120 mtpa between 2019 and 2038 (and almost certainly beyond) – requiring the equivalent of 10.7 to 15.7 Bcf/day of natural gas feedstock for B.C. LNG facilities, not counting energy requirements and process losses.

The B.C. government estimates are among the highest and are, according to many industry analysts, unrealistic at the present time (Petroleum News 2013; The Pembina Institute 2013; Mirski and Coad 2013). However, the Province's continued reference to these scenarios requires that they be considered in this analysis.

5.2 PROPOSED LNG FACILITIES

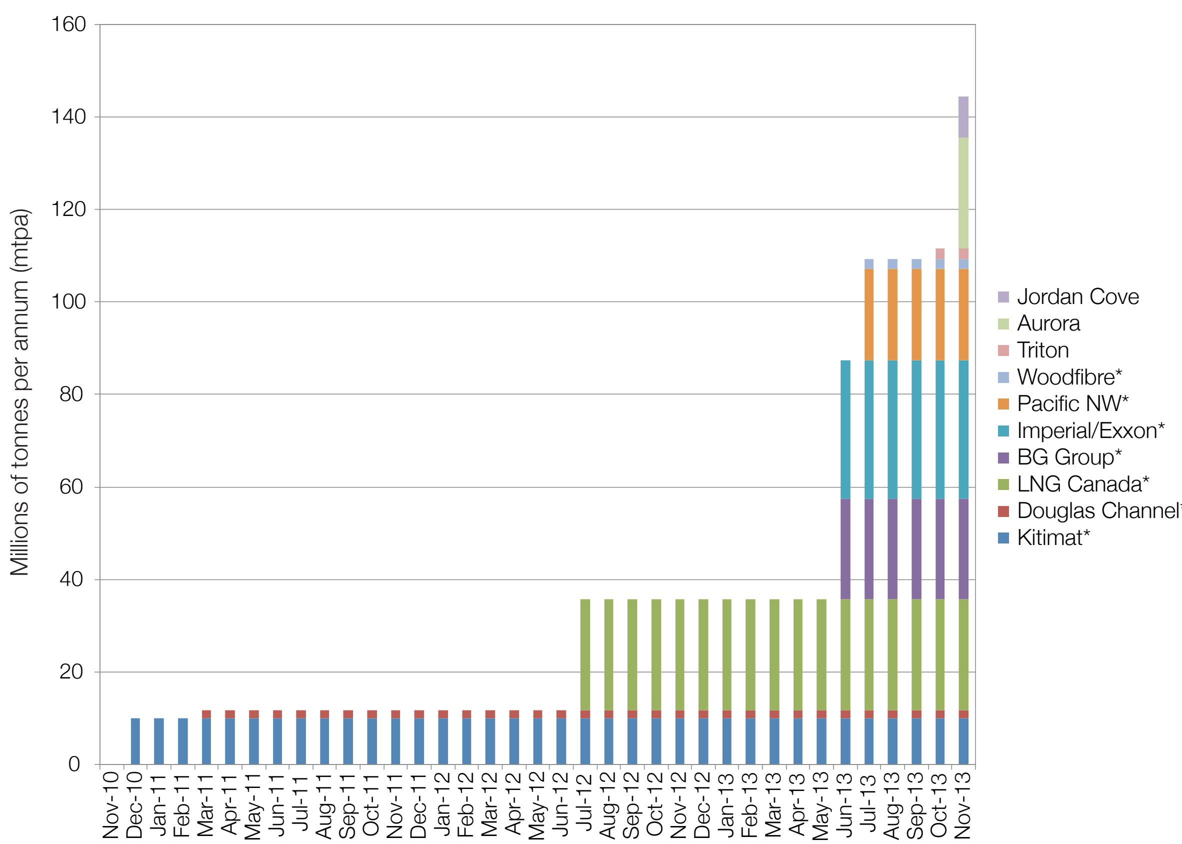
Actual current LNG facility proposals represent the second source of information from which to triangulate potential future LNG export capacity scenarios.

As of July 5, 2013, B.C. officially recognized six projects with proposals for 107.1 mtpa of LNG export capacity.[27] By November 2013, this had grown to ten proposed LNG facilities in various stages of the project planning process, with a combined LNG export capacity of 144.8 mtpa equivalent to approximately 18.9 Bcf/day.

Figure 4 below shows the total NEB export licence application amounts proposed for B.C. (or linked – Jordan Cove) LNG facilities as of November, 2013. Others may yet come as companies with holdings in the WCSB or strong ties to the global LNG sector attempt to break into this fledgling market.

If all 10 of the projects listed in Figure 4 were to go ahead, gas requirements (not including gas inputs for power and process losses) would be over 140 mtpa already, well above the range (82–120 mtpa) used by the B.C.

Figure 4: NEB export license applications, and licenses already granted,* as of December 2013



Note: *Starred projects indicate NEB export licences already granted.

27 newsroom.gov.bc.ca/2013/07/bc-welcomes-sixth-lng-export-application.html

government in its economic benefits estimations. Thus, the data from current NEB export licence applications supports an extremely high "ceiling" estimate of total LNG demand growth as high as 18.9 mtpa. Most industry experts (see Section 5.3) agree this amount of B.C. LNG exports is extremely unlikely.

Relevant currently proposed LNG projects are described below and examined in further detail in Table 3:

- **DOUGLAS CHANNEL ENERGY PROJECT** – Proponents are LNG Partners and Haisla Nation. Located in Kitimat (floating facility). Received a 20-year export licence in February 2012, authorizing the export of 1.8 mtpa of LNG (approximately 0.10 Bcf/day). No environmental assessment required.

- **KITIMAT LNG** – Proponents are Apache Canada Ltd. and Chevron Canada Limited. Located in Kitimat. Received a 20-year export licence in October 2011, authorizing the export of 10 mtpa of LNG (approximately 1.3 Bcf/day). Purchase agreements have either been signed or in final negotiations with customers in China, Malaysia, South Korea and elsewhere in Asia Pacific (Redden 2012). Environmental assessment certificate received.

- **LNG CANADA** – Proponents are Shell Canada Ltd., Korea Gas Corporation (KOGAS), Mitsubishi Corporation and PetroChina Company Limited. Located in Kitimat. Received a 25-year export licence in February 2013, authorizing the export of 24 mtpa of LNG. Environmental assessment ongoing.

- **PACIFIC NORTHWEST LNG** – Proponents are PETRONAS, its wholly owned subsidiary Progress Energy Canada Ltd., and Japan Petroleum Exploration Co. Located just south of Prince Rupert on Lelu Island near Port Edward. Submitted an application to the NEB on July 5, 2013, to export 19.68 mtpa of LNG for 25 years, approved in December 2013. Environmental assessment ongoing.

- **PRINCE RUPERT LNG** – Proponent is BG Group plc. Located in Prince Rupert. Submitted an export licence application to the NEB in June 2013, to export 21.6 mtpa of LNG for 25 years, approved in December 2013. Environmental assessment ongoing.

- **WCC LNG LTD. PROJECT** – Proponents are Imperial Oil Resources Limited and its parent company ExxonMobil. Will be located in the vicinity of Kitimat or Prince Rupert. Submitted an application to the NEB in June 2013 (WCC LNG Ltd. 2013) to export up to 30 mtpa of LNG for 25 years; approved in December 2013, this is the largest current proposal, requiring 1.46 Tcf of gas per year at full capacity, although initial design capacity is 15 mtpa.

- **WOODFIBRE LNG PROJECT** – Proponents are Woodfibre Natural Gas Ltd. Small-scale LNG processing and export facility of 2.1 mtpa (Priddle 2013b), located approximately 7 km southwest of Squamish. Existing Fortis BC pipeline would transport natural gas to the site. Based on current timelines, Woodfibre LNG could be operational by 2017. NEB export licence approved December 2013.

- **TRITON LNG** – Proponents are Japan's Idemitsu Kosan (50 per cent) and Canada's AltaGas (50 per cent). Feasibility studies for a floating liquefaction facility to be completed in 2014 with earliest export terminal possibility at an as yet undecided location in the Kitimat or Prince Rupert area being 2017. The Proponent has applied for an NEB export license of 25 years for 2.3 mtpa (325 Mmcf/day or 115 Bcf/yr).[28] Linked to the PNG Looping pipeline proposal.

28 The NEB export license application for this project is available at https://docs.neb-one.gc.ca/ll-eng/llisapi.dll/fetch/2000/130635/1057148/A3Q3C5_-_Application_for_Licence_to_Export_Natural_Gas.pdf?nodeid=1057149&vernum=0

- **AURORA LNG**[29] – Proponents are Nexen Inc. and a consortium led by INPEX Corp. of Japan. Nexen is now a wholly owned subsidiary of CNOOC Limited, the largest importer of LNG into China (Aurora Liquefied Natural Gas Ltd. 2013). The partners have a joint venture to develop shale gas assets in all three FNFN territory basins and have recently secured options on land at Grassy Point, north of Prince Rupert and the First Nations community of Lax Kw'alaams (Thomas 2013). The joint venture's stated goal is to maximize the value of its shale gas resources in FNFN territory (Aurora Liquefied Natural Gas Ltd. 2013).

- **DISCOVERY LNG**[30] – Proponent is Quicksilver Resources Canada Inc. The location is near Campbell River, B.C. at an abandoned paper mill. No estimate of the size of the facility has been put forward, nor have any formal applications been made to regulators. The facility would be designed to use gas from Quicksilver's Horn River Basin holdings.

The Jordan Cove LNG export facility proposed for Oregon has also identified plans to export as much as 1.55 Bcf/day of WCSB gas (Jordan Cove LNG L.P. (2013),[31] and so is included in Table 3 on the following page.

Not included in Table 3 are Kitsault Energy's very initial plans to develop an LNG export facility at Kitsault, B.C. (Environmental Law Centre 2013, 35). Nor are the recently proposed east coast facilities of Goldboro in Nova Scotia, which plans for 5 mtpa capacity (Lewis 2012) or Canaport in New Brunswick, a Repsol/Irving Oil import facility proposing a 1.2 Bcf/day export volume (equivalent to about 9 mtpa). In addition to being unlikely to fuel the Asian LNG market, neither project would likely use WCSB gas.

The currently proposed B.C. facilities, even if only some proceed, will fundamentally alter B.C.'s and the WCSB's shale gas sector. As noted by *The Vancouver Sun*:

> *If only four of them go ahead, it would mean tripling British Columbia's current natural gas production of three billion cubic feet a day to nine billion cubic feet just to meet their needs.*[32]

Indeed, if all proceeded, the WCSB's annual production would likely have to more than double from 13 to 14 Bcf/day to over 30 Bcf/day.[33]

The liquefaction facilities are not the only new major industrial developments required in an integrated B.C. LNG production system. Natural gas pipelines, almost all of them new and many of them extremely large and most dedicated to a single LNG facility, will be required. Associated pipelines currently proposed to transport upstream gas to liquefaction facilities include the following:

- The 480 km Pacific Trails Pipeline: to Kitimat LNG, connected to Spectra Energy's West Coast Pipeline System; due online in 2017.

---

29 nexencnoocltd.com/en/Operations/ShaleGas/AuroraLNG.aspx

30 discoverylng.com

31 Jordan Cove's request for as much as 1.55 Bcf/day of feedstock gas to fuel a 9 mtpa facility is a good illustration of the conservative nature of Firelight's feedstock estimates in this study. Using our conversion calculations, nine mtpa of LNG equates to 1.18 Bcf/day. The remaining 370 Mmcf/day of gas sought by Jordan Cove in its NEB export licence application may be reflective of power requirements and/or process losses. This additional amount represents about 25 per cent of the total gas requirements for Jordan Cove. Firelight has not included these additional gas requirements in our estimates for any of the facilities herein.

32 canada.com/vancouversun/news/business/story.html?id=65b07204-7897-451b-b6c8-c52e56d4a5ed

33 This assumes no North American demand increases for WCSB gas.

Table 3: B.C. LNG export facility proposals as of November 2013

Project	Project partners	Capital cost	Associated pipeline	Maximum capacity/yr	Licensing	Other notes
Kitimat LNG (KLNG)	Apache Corp. (50%), Chevron Corp. (50%)	$4.5 billion	Pacific Trails Pipeline (Summit Lake to Kitimat –to be built and linked to Spectra Energy Westcoast Pipeline system at Summit Lake)	10 mtpa (5 mtpa initially)	Environmental assessment complete; Export licence issued Oct 2011; 2016 in service goal	Site preparation underway at Bish Cove, near Kitimat
Douglas Channel LNG	B.C. LNG Export Cooperative, comprising: LNG Partners (Texas-based) (50%), HBLP (Haisla Nation) (50%)	$500 million	Pacific Northern Gas Pipeline (pre-existing);	1.8 mtpa	Environmental assessment not required; Export licence issued Feb 2012; 2015 in service goal	Barge plant on west side of Douglas Channel. Haisla FN granted rights to lease or buy land for terminal. Expects to use BC Hydro power
LNG Canada	Royal Dutch Shell PLC (40%), Korea Gas (Kogas) (20%), Mitsubishi (20%), PetroChina Company Limited (20%)	$4 billion	Coastal GasLink Pipeline (subsidiary of TransCanada Pipelines) from Hudson's Hope to Kitimat	12 to 24 mtpa (3.2 Bcf/day)	Environmental assessment ongoing; Export licence issued February 2013; in service goal of 2018	Kitimat location
Prince Rupert LNG	British Gas Group	>$10 billion	Spectra Westcoast Connector Pipeline from Chetwynd to Prince Rupert	14 to 21.6 mtpa (2.9 Bcf/day)	Environmental assessment ongoing; Export licence pending; in service goal of 2019-2020	Ridley Island Industrial Site location (Prince Rupert)
Pacific Northwest LNG	Petronas (nationalized Malaysian company) and Japan Petroleum Exploration Co.	>$10 billion	TCPL Prince Rupert Gas Transmission Project from Hudson's Hope to Prince Rupert	12 to 18 mtpa (2.7 Bcf/day)	Environmental assessment ongoing; Export licence pending; in-service goal is 2018	Lelu Island location (Prince Rupert)
WCC LNG Ltd. Project	Imperial Oil/ExxonMobil	No info	Unknown at this time	15 to 30 mtpa (5.5 Bcf/day)	Export licence pending; plans one new train a year starting 2021	No location chosen; Kitimat or Prince Rupert area
Woodfibre LNG Project	Pacific Oil and Gas (Indonesia)	No info	Existing Fortis BC pipeline	2.1 mtpa (280 Mmcf/day)	Export licence pending	Woodfibre mill site, southwest of Squamish in Squamish Inlet
Triton LNG	Idemitsu (Japan) and AltaGas	No info	Unknown at this time	2.3 mtpa	Export licence pending	Floating facility proposed for either Prince Rupert or Kitimat
Aurora LNG	Nexen/CNOOC, INPEX (Japan), JGC Exploration Canada Ltd.	No info	Unknown at this time	24 mtpa	Export licence pending; in service goal of 2021 to 2023	Grassy Point, northwest of Prince Rupert
Discovery LNG	Quicksilver Resources (seeking partner[s])	No info	Unknown at this time	Unknown at this time	No applications made	Facility located at Elk Falls mill site near Campbell River
Jordan Cove	Jordan Cove LNG L.P.	No info	Existing Canadian – U.S. pipelines including TCPL system and Spectra Energy from Fort Nelson	9 mtpa (1.55 Bcf/day)	Export licence pending	In Oregon; plans to use WCSB gas

Sources: Crist (2013), Aurora Liquefied Natural Gas Ltd. (2013), CERI (2012), NEB export licence applications, and websites including the web-linked project names on the previous page.

- TransCanada PipeLines' (TCPL) Prince Rupert Gas Transmission (PRGT): with initial capacity of 2.0 Bcf, expandable to 3.6 Bcf/day to move Montney and Horn River gas to the Pacific Northwest LNG facility in Prince Rupert; in service proposal for 2018.

- TCPL's 1.7 Bcf/day Coastal GasLink, linking Horn River (and Montney) gas with Shell's planned 12–24 mtpa LNG Canada facility year Kitimat, in service by the latter part of this decade.

- Spectra's Westcoast Connector Gas Transmission Project: Spectra and the BG Group are proposing a 48-inch pipeline, the largest size in use in North America. It would be capable of delivering 4.4 Bcf/day of natural gas to Prince Rupert, more than all the gas currently being produced in B.C.

Other pipeline connections from FNFN territory and other gas producing regions in the WCSB into the B.C. and Alberta mainline systems of companies like TCPL and Spectra would also be necessary. Current infrastructure to move and process gas from FNFN basins is inadequate to handle the required increases in production. Projects like TCPL's Komie North Project from the northern portion of the Horn River Basin, the proposed TCPL North Montney mainline, and others would be required to shore up infrastructure gaps.[34] Table 4 on the next page identifies LNG-related pipeline proposals, while Figure 5 identifies the routes proposed for several currently proposed dedicated LNG pipelines to B.C.'s coast.

By November 2013, a total B.C. LNG export capacity of almost 145 mtpa had been applied for. If even half of that amount is built, Canada would become the world's second largest exporter of LNG, after Qatar.

By the end of December 2013, over 105 mtpa of export licences had been issued by NEB (2013c), signaling regulatory if not yet market support for that amount of LNG export from the west coast of Canada. This is an important recognition. As part of export licencing, the NEB requires the proponent show that their export of natural gas will not have a material detrimental effect on the ability of Canadians to access natural gas or the price of same. By issuing export licences for this level of LNG export, the NEB is signaling that the Canadian gas production system, 98 per cent of which is within the WCSB, is robust enough to handle this increase of some 13.65 Bcf/day over and above the existing 13-14 Bcf/day currently produced for the North American markets – an effective doubling of the WCSB gas extraction sector.[35]

In addition, industry analysts such as Priddle (2013a; 2013b) and Ziff Energy Group (2013a; 2013b), are regularly conducting export impact assessments that suggest none of the currently proposed LNG facilities are likely to adversely impact on Canada's ability to maintain adequate domestic gas supply and reasonable gas prices (for a counter-argument, see Hughes 2014).

34 In addition, rapid and extensive increases in gas plants and a variety of other natural gas production system components will be necessary. This issue of required additional physical works and activities is taken up in more detail in the Phase 2 report.

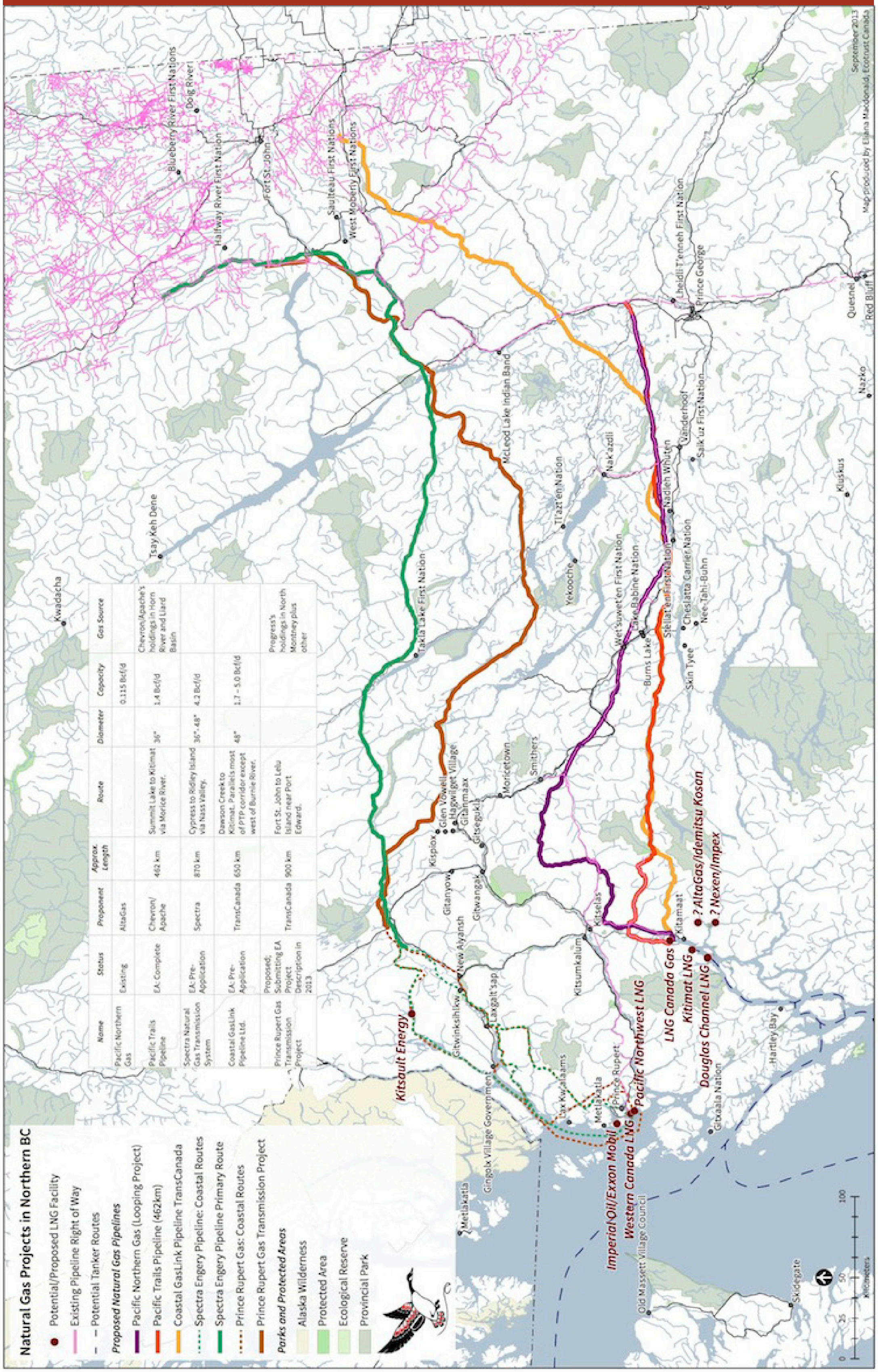
35 One problem is that the NEB examines each LNG export licence proposal in isolation from other applications, requiring little if any consideration of cumulative effects of range of combined LNG export projects. This suggests a failure in the Canadian regulatory system to meaningfully include cumulative effects assessment in decision-making, another issue taken up in more detail in the Phase 2 report.

Table 4: B.C. LNG pipeline proposals as of November 2013

Pipeline name	Project owner	Linked LNG facility	Location of start / end points	Length (km)	Capacity (Bcf/day)	Status
Prince Rupert Gas Transmission (PRGT)	TransCanada Pipelines	Pacific Northwest LNG	Near Hudson's Hope to Lelu Island near Prince Rupert	750	2 (potential to expand to 3.6)	Application stage of B.C. EA process Construction start: 2015 In-service: 2018
Westcoast Connector Gas Transmission Project	Spectra (and BG Group)	Prince Rupert LNG	Cypress (210 km south of Fort Nelson) to Ridley Island near Prince Rupert	851-872	Up to 4.2	Application stage of B.C. EA process Construction start: 2015 In-service: 2018
Pacific Northern Gas (PNG) Looping (upgrade)	Pacific Northern Gas (PNG)	Douglas Channel LNG	Summit Lake to Kitimat	525	0.6	Pre-application of B.C. EA process Construction start: 2014 In-service: 2016
Pacific Trails Pipeline	Partnership between Chevron Canada Ltd. and Apache Canada Ltd.	Kitimat LNG	Summit Lake to Kitimat	463	1.0 to 1.5	EA Certificate issued, amendment required
Coastal GasLink	TransCanada Pipelines	LNG Canada	Near Dawson Creek to Kitimat	650	1.7 (potential to expand to 5.0)	Application stage of B.C. EA process Construction start: 2015 In-service: 2018
Komie North	*TransCanada Pipelines*	*n/a (linked to Quicksilver)*	*Fortune Creek Gas Plant to Cabin Gas Plant in Horn River Basin*	*100*	*Unknown (36 inch pipe)*	*Rejected by NEB in 2013 due to tolling issues; proponent may reapply*
North Montney Mainline (TCPL 2013)	*TransCanada Pipelines*	*Could be several; links to PRGT and Coastal GasLink*	*From northern portion of Montney to Farrell Creek*	*305*	*Unknown (48 inch pipe)*	*Applications filed with NEB in late 2013 Construction start 2015; in service between 2017 and 2019*

Note: Most of the information for this table comes from the respective Project Descriptions available on the B.C. Environmental Assessment Office website, http://a100.gov.bc.ca/pub/epic/projectStatusCategoryReport.do#curr Information on the linked LNG facilities comes from various company websites. Italicized projects are not linked to any specific LNG facilities but would increase gas transportation capacity to existing systems and newly proposed dedicated LNG pipelines.

Figure 5: Proposed LNG project-related pipelines in B.C. as of September 2013



Note: View this map in high resolution at http://fnlngstrategy.ca/top-proposed-lng-lines-in-bc/

Source: Carrier Sekani Tribal Council, Treaty 8 Tribal Association and Ecotrust

5.3 INDUSTRY ANALYST ESTIMATES

Several groups of very different backgrounds, including Ziff Energy Group, the Fraser Institute, and the Pembina Institute, have provided estimates of B.C. coastal LNG export potential. A variety of these estimates are listed in Table 5.

Table 5: Industry and analyst B.C. LNG export scenarios

Source	Potential B.C. LNG Export Gas Requirements
Antunes et al. (2012)	2.6 Bcf/day, with four trains staring in 2016, 2018, 2019, and 2021 respectively
Ziff Energy Group (2012)	8.7 Bcf/day by 2024
Fraser Institute (2012)	7.1 Bcf/day by 2032
Pembina Institute (2013)	Low: 3.13 Bcf/day; Medium: 5.26 Bcf/day; High: 9.25 Bcf/day (no date)
Walden (2013)	8 Bcf/day by 2030
Ziff Energy Group (2013a)	5.0 Bcf/day in 2050, starting in 2017
Ziff Energy Group (2013b)	4.9 Bcf/day starting in 2020
Ziff Energy Group (2013c)	7.6 Bcf/day in 2050

Industry experts have estimated rapid growth for the B.C. LNG export sector. Ziff Energy Group (2012) pegged B.C. coastal LNG export potential at 8.7 Bcf/day by 2024, ramping up from four Bcf/day in 2020 and eight Bcf/day in 2022. However, this estimate was made in advance of the most current LNG proposals, such as those of BG Group and Petronas. Nonetheless, Ziff Energy Group later revised its estimates downwards on three separate occasions (Ziff Energy Group 2013a; 2013b; 2013c) down to between 4.9 and 7.6 mtpa in later reports for LNG proponents in the NEB export licencing process. Ziff Energy Group (2013b, 31) does however recognize that "there is gas resource potential available for higher levels of North American LNG export than indicated here."[36]

Both the lowest end estimates of 2.6 Bcf/day by Antunes et al. (2012) and 3.13 Bcf/day by the Pembina Institute appear highly conservative in light of current proposals for over six times their amounts.[37]

Industry analysts' estimates are generally grouped in the four to eight Bcf/day range, roughly the LNG equivalent of 30 to 60 mtpa. Ziff Energy Group's 2012 estimate correspond well with other estimates by groups like the Canadian Energy Research Institute (Walden 2013), which estimated eight Bcf/day of LNG facilities by 2030 (also estimated prior to 2013's large growth in NEB export licence proposals).

36 Indeed, Ziff Energy Group's estimates are less actual predictions and more of a formula – generally the addition of the Project being considered (e.g., in the case of Ziff Energy Group 2013b, Triton LNG) to already approved NEB export licences.

37 The Pembina Institute's (2013) estimates were based on only the initial phases of the Petronas and Shell projects proceeding. Both the Pembina Institute and the Antunes et al. (2012) estimates also came out before some of the largest NEB export licences were applied for.

5.4 ESTIMATING A B.C. LNG EXPORT CAPACITY RANGE

"…all of the key ingredients for success are now becoming aligned. Detailed plans have been developed, hearings have been held, political support has firmed, and the economic drivers are strong." – Steve Davis and Associates Ltd. (2011, 45), on the potential for development of a successful B.C. LNG export sector

While optimism about the growth of a B.C. LNG sector has been high in many quarters, some analysts (e.g., Mirski and Coad 2013; Macquarie Research 2012a) remain skeptical about the size of the sector. As described in Section 4 of this report, there are a large number of proposed global suppliers to fuel a limited amount of global demand. A brief discussion of the comparative advantages and disadvantages of B.C.[38] versus other current and proposed LNG exporting countries is necessary prior to establishing a realistic range of B.C. LNG export demand scenarios. Several are outlined in Table 6 on the following page.

The B.C. government is currently focused on emphasizing B.C.'s advantages. In contrast, there has been little strategic, publicly accessible, government analysis of the potential risks associated with B.C.'s disadvantages, even though they are clearly evident to industry analysts. There is a danger in this, as expressed by the Environmental Law Centre (2013, 11):

> *…if even one of these risks materializes, we are unlikely to be able to participate successfully in the global LNG market. Thus, we could be left with the bill for extremely costly infrastructure and without customers – or have to grant costly subsidies, tax breaks and loosening of regulations to keep the industry alive.*

In addition, there are increasing signs that Asian customers will seek LNG pricing linked not merely to world oil prices, as is the historic norm, but "at least partially indexed to North American natural gas prices" (Mirkski and Coad 2013, 15). While this could give B.C. projects some advantages over LNG projects from other parts of the world (given North America's low natural gas prices), the effect could be damaging on those B.C. LNG projects and gas producing regions that have higher break even costs.

A range of potential B.C. LNG export capacity scenarios is shown in Figure 6 on page 44.

In general, the author suggests that the figures arising from industry analysts are a better estimate than those presented by the B.C. government. In addition, the current proposals of more than 18 Bcf/day in NEB export licences, equivalent to over 140 mtpa, are unrealistic. Not enough excess global LNG demand is in place to support this amount of B.C. LNG exports.

As a point of comparison to these B.C. estimates, the author examined scenarios developed by the U.S. Energy Information Administration (U.S. EIA 2012), of potential future U.S. LNG exports, primarily from the Gulf Coast states of Texas or Louisiana. The U.S.

38 B.C. is considered the primary if not sole likely Canadian LNG export jurisdiction due to its proximity to major markets in Asia, its proximity to gas producing regions in the WCSB (which holds over 90 per cent of Canada's gas reserves and 97 to 98 per cent of current production), and the likely inability of east coast facilities to compete against U.S. Gulf Coast producers and other existing and proposed LNG exporters to Europe (in particular). Also reflecting this is that there are nine currently proposed B.C. facilities, and only two on Canada's east coast.

Table 6: Potential B.C. advantages and disadvantages as an LNG exporter

Potential B.C. Advantages	Potential B.C. Disadvantages
Massive gas reserves in WCSB	Slow start means "we may be rushing headlong into a global supply glut" (Environmental Law Centre 2013, 9)
Established unconventional gas sector	Higher costs for greenfield projects than U.S. Gulf Coast retrofitting of LNG import facilities (Walden and Walden 2012)
Lower labour and capital costs for greenfield projects than Australia	High competition for skilled labour and potential domestic labour shortfalls (especially alongside oil sands sector)
Proximity to market: lower shipping time and costs to Asia than U.S. Gulf Coast states[a]	Developing the sector at historically high price differential between North American and Asian gas prices lends to uncertainty if gap closes,[b] which it may if oil indexing reduces in Asia
Signs of vertical integration of offshore purchasers and users of LNG into B.C. (see Section 6.6), potentially more readily securing supply of gas, avoiding pricing fluctuations, and achieving economies of scale[c]	Current lack of strategic infrastructure planning (e.g., a single or two pipeline corridors)
Political stability and friendly environment for foreign investment, support for an LNG sector at the provincial and national levels, and associated "regulatory certainty"	Weaker existing pipeline linkages to coastal facilities than U.S., increasing costs
	Higher gas production costs than U.S. shales

Notes: [a] Apache Corp. (2013) notes northern B.C. ports like Kitimat are 10 days sailing to Tokyo versus 16 days from Qatar. And B.C. ports have a strong locational advantage to Asia over U.S. Gulf Coast projects. However, this advantage may shrink with the completed widening of the Panama Canal, scheduled for 2015 (Thomson Reuters 2013).

[b] This gap could close if a global LNG supply glut emerges, or if China and India find ways to exploit their large domestic unconventional gas sources. Both could drive down Asian gas prices and push higher price proposals and gas input cost regions out of profitability (for a further discussion, see Environmental Law Centre 2013; Mirski and Coad 2013).

[c] For example, Poten & Partners (2010, 3) suggest that one of the strengths of the Kitimat LNG proposal is it "… has strong equity players in the liquefaction project, with considerable reserves and supply available to be committed to the plant and clear strategic alignment toward monetization [of upstream supply] through LNG."

Source: Material from Macquarie Research (2012a; 2012b), CAPP (2012), Environmental Law Centre (2013), International Gas Union (2013), UPI (2013), Ernst & Young (2013a), Poten & Partners (2010), Mirski and Coad (2013) and other sources is incorporated into this table.

and Canadian markets are similar in abundant supplies and high levels of current proposals to develop LNG facilities, so this comparison was deemed a useful point of triangulation for the Canadian numbers.[39] U.S. EIA (2012) estimates that U.S. LNG exports will average between six and 12 Bcf/day over the next 20 to 25 years. This corresponds with the mid-to-high range of B.C. LNG export market estimates.[40]

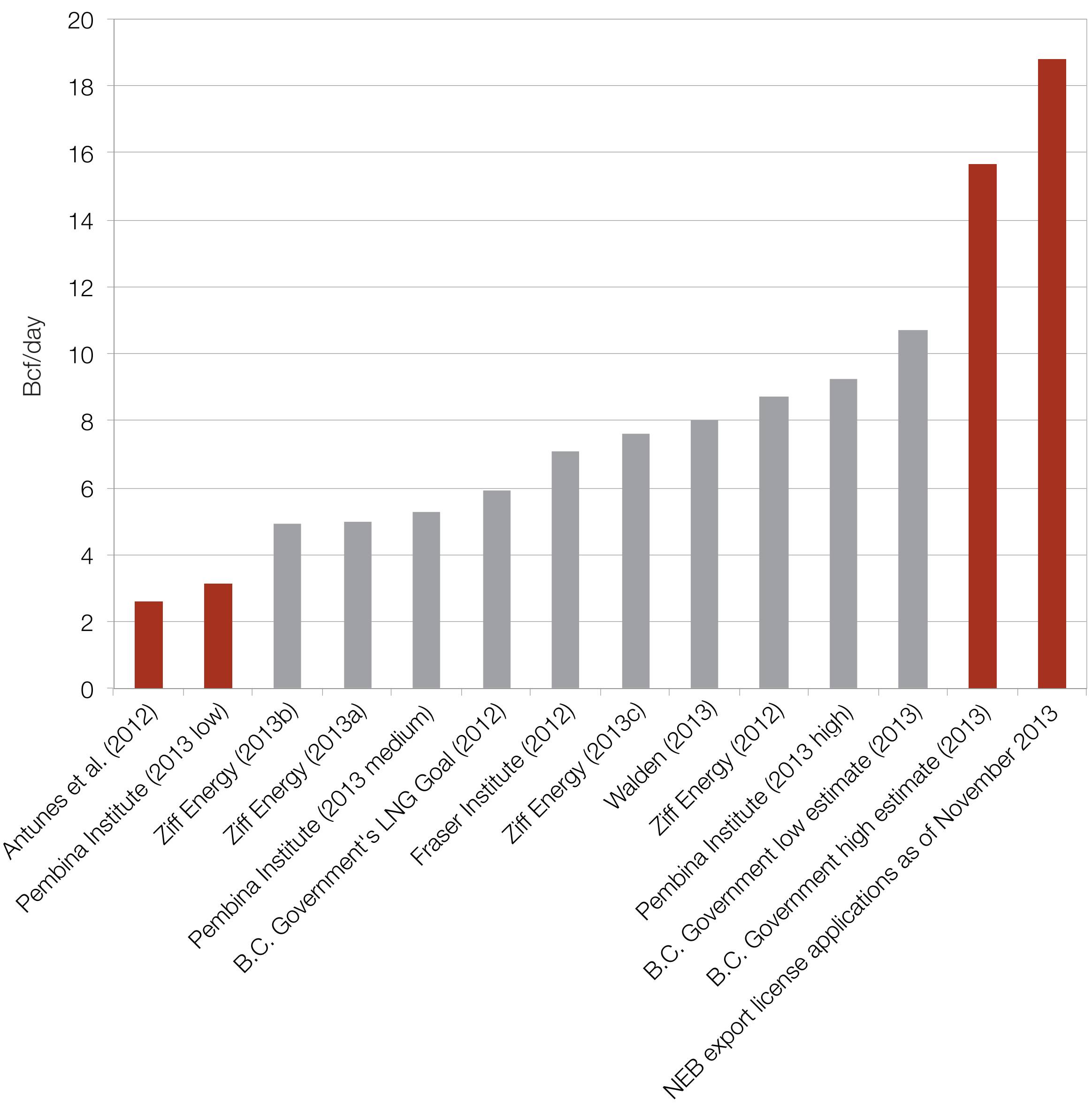
There is clearly a wide range of potential LNG export futures for B.C., starting within the next five years and extending well beyond the 20 year range used in this study. The author finds the low end estimates by Antunes

39 Indeed, it is arguable that the closer proximity of B.C. coastal facilities to the major Asian markets of Japan, South Korea, and China provides an advantage to Canadian West Coast facilities over U.S. Gulf Coast facilities (Apache Corp. 2013; Macquarie Research 2012a).

40 Offering a slightly more pessimistic perspective on U.S. LNG is Ziff Energy Group (2013c), which estimates the U.S. will be exporting only 4 Bcf/day by 2050, versus 7.6 Bcf/day from Canada.

et al. (2012) and The Pembina Institute (2013) unconvincing in light of current proposals for over seven and six times these amounts, respectively. These production estimates would likely see only one large or a couple of medium-size LNG facilities built. The Ziff Energy Group (2013b) estimate of 4.9 Bcf/day (37.5 mtpa) starting around 2020 and staying consistent thereafter is a more useful low end estimate. As a result, the two lowest-end estimates have been removed from consideration (they are highlighted in red in Figure 6).

Figure 6: B.C. LNG export scenario estimates (converted to Bcf/day)



Similarly, at the high end the author has highlighted in red as unrealistic both the LNG export licences and applications amount of 144.5 mtpa and the B.C. government's high end 120 mtpa estimate (as reported in Ernst and Young 2013b). The B.C. government's high-end estimate has been deemed unrealistic by a variety of industry analysts. The even higher current NEB export licences and applications amount would represent an unrealistic one-third of expected global LNG demand by 2020.

This study adopts a range between a low of 4.9 Bcf/day and a high of 10.7 Bcf/day (the B.C. government's 2013 low-end estimate) as a range of average annual LNG exports from British Columbia between 2018 and 2038. This is equivalent to between 37.5 mtpa and 82 mtpa.

The author notes a strong cohort of estimates between 5 and 9 Bcf/day (38 to 69 mtpa). Nonetheless, this report does not attempt to forecast which number in this range is the most likely outcome; each outcome within this range is deemed equally likely to occur.

This study adopts a range between a low of 4.9 Bcf/day and a high of 10.7 Bcf/day (the B.C. government's 2013 low-end estimate) as a range of average annual LNG exports from British Columbia between 2018 and 2038. This is equivalent to between 37.5 mtpa and 82 mtpa.

Most importantly: change is clearly coming. Ten LNG facilities have been proposed in the past two to three years that would rely on WCSB gas sources. In total, they are for LNG export capacity of more than 140 million tonnes per year. To put some context to this, this equals about 6.9 trillion cubic feet of natural gas per year, or over 18 billion cubic feet per day. In 2012, gas production from FNFN territory was less than 400 million cubic feet per day (1/45th of the total applied for LNG export licenses), and B.C. in total only produced about 3.5 billion cubic feet of sales gas per day (1/5th of the total proposed LNG export capacity). At least two of the proposed pipelines to liquefaction facilities could by themselves exceed this capacity. While nowhere near this much LNG capacity is likely to be developed, the high end of the reasonable range would still be equivalent to three times B.C.'s existing gas production and almost as much as current WCSB production.

SECTION 6

Estimating LNG-Induced Gas Extraction from FNFN Territory

"When commodity prices crater and supply exceeds hometown demand, you can either shut in production and await better times, or if you happen to be a producer in the gas-rich Horn River and Montney shale plays of British Columbia, seek out markets elsewhere, in this case some 8,000 miles away" – Redden (2012, 64).

WITH A CREDIBLE RANGE OF B.C. LNG EXPORT CAPACITY ESTABLISHED, this section of the report focuses on estimating how much of that export volume may be filled by gas extracted from FNFN territory. This is perhaps the most important contribution of this report. To our knowledge, there have been no previous publicly available scenarios developed of how much of the B.C. LNG export sector gas supply would come from different Canadian gas supply regions.

This analysis uses five methods to help triangulate what proportion of natural gas production used to fuel the B.C. LNG export sector will come from FNFN territory:

1. Current FNFN gas production as a proportion of current WCSB totals;
2. FNFN gas-in-place as a proportion of WCSB totals;
3. Industry, government and analysts' future estimates of basin-by-basin production;
4. Factors affecting basins' comparative advantages in the supply of LNG; and
5. Vertical linkages of current FNFN territory gas tenure holders to proposed LNG facilities.

As noted previously, any production and reserves from the portion of North Montney within FNFN territory (see Figure 1) is not included as part of the calculations for FNFN territory herein.

6.1 KEY WCSB GAS FORMATIONS

> *While there are several intriguing shale plays in Western Canada, the two most promising are in the Horn River Basin and the Montney.* – Walden and Walden (2012, 5)

To understand where gas to fuel the LNG export sector will come from, a deeper understanding of key WCSB gas basins is critical. Select characteristics of several are discussed below.

6.1.1 Horn River Basin

> *Encana Corp. estimates the Horn River shale could hold as much as 500 trillion cubic feet of natural gas, which places the find among North America's largest discoveries.* – Oil and Gas Financial Journal (2012)

The Horn River Basin has been subject to oil and gas exploration as far back as 1955 for conventional deposits. It was known for many years that the area's shale layers held substantial gas resources, but only with recent horizontal drilling and fracking technologies has the basin become economic for large scale exploration and production potential (B.C. OGC 2010). In 2006, both Encana and Apache successfully used hydraulic fracturing techniques to determine if economic gas production was possible, thus beginning the Horn River Basin shale gas era (KM LNG 2010).

According to the B.C. OGC (2013b), the Horn River Basin covers about 1.1 million ha in northeastern B.C. (11,000 km^2), beginning at Fort Nelson and heading north beyond the border with the Northwest Territories. The B.C. OGC (2010) estimates that the Horn River Basin has approximately 500 Tcf[41] of natural gas in place. The same report states that Horn River Basin shales have a high "resource density" (up to approximately 151 Bcf/mi^2, according to a U.S. EIA report from 2013[42]). Advanced Resources International Inc. (2013) estimates the Horn River Basin has risked gas-in-place values of 530 Tcf, with 133 Tcf recoverable. Petzet (2008) suggests that the Horn River Basin has higher gas in place density values than the largest U.S. play – the Barnett Shale in Texas. This means there is a higher than average amount of gas per unit of land, making wells more productive.

However, high production costs and low gas prices have limited extraction to date. NEB (2010) suggested that the average cost of producing Horn River Basin shales was $4.68/GJ in 2009 (equivalent to about $4.45 per thousand cubic feet), not including pipeline tolls. This cost is not economic at current North American prices, but could become more attractive if costs continue to decline, which is "typical for shale gas as development proceeds" (B.C. MEM and NEB 2011, 6).

Redden (2012) identified the busiest companies working in Horn River Basin between 2003 and 2011. Apache has the strongest landholding and "remains the basin's most active operator with an interest in more than 400,000 acres" (Redden 2012, 68). Apache has been at the forefront of multi-well pads, in 2011-12 concluding hydraulic fracturing operations on a 16-well pad in the Horn River Basin. Redden (2012) reported that Apache held an unrisked resource of 9 to 16 Tcf in the Horn River Basin as of 2011.

---

41 Other estimates range from 372 – 529 Tcf, with the most critical element, the marketable resource, estimated at 78 Tcf by the NEB (2010) and as high as 110 Tcf by industry analysts (Oil and Gas Financial Journal 2012).

42 eia.gov/analysis/studies/worldshalegas/pdf/chaptersi_iii.pdf. In addition, B.C. OGC (2010, 7) suggests that the "resource density of the HRB (Horn River Basin) shales is very high, with over one billion cubic feet of gas per meter of reservoir per square mile anticipated." If the thickness is between 100 and 200 metres on average, this aligns closely with the estimates used in the U.S. EIA study.

Between 2003 and 2011, Apache drilled 72 wells targeting shale gas in the Horn Rriver Basin. In December 2010, Apache identified an aggressive future growth plan for the Horn River Basin, with an average of 50 wells planned per year between 2012 and 2034, for a cumulative total of 1218 wells between 2010–2034. With this development plan in place, Apache estimated its share of production (just over 50 per cent) would grow from 35 Mmcf/day to 530 Mmcf/day in 2020, to 734 Mmcf/day in 2030, and 773 Mmcf/day by 2034 (KM LNG 2010).

Other companies with strong interests in the Horn River Basin include Nexen, Imperial Oil, Devon and Quicksilver Resources.

Despite the fact the Horn River Basin has experienced a great deal of development over the past decade, it is still deemed "immature" by gas sector analysts. This means that the vast bulk of its gas resources have yet to be tapped. Its attractiveness, like that of the Liard Basin (see below), lies largely in its "prolific" flow rates (($S\&T^2$) Consultants Inc. 2010) and its high total gas in place, estimated in some locations to be as high as 150 Bcf/mi^2 (KM LNG 2010).[43] The Horn River Basin has much higher EUR than most other gas plays in North America of as high as 12.0 Bcf/well (KM LNG 2010, 7).[44]

6.1.2 Liard Basin

> *Apache's early results from Liard are described as "the most prolific shale gas resource test in the world."* – Apache Corp. (2012)

The Liard Basin covers an area of approximately 11,140 km^2 northwest of Fort Nelson. It is roughly centred on the confluence of the Liard and Fort Nelson Rivers, at the FNFN ancestral village of Nelson Forks. Its eastern border is defined by the Bovie Fault, which separates it from the Horn River Basin. Its northern boundary in B.C. is defined by the B.C./Yukon/NWT border.

According to Advanced Resources International Inc. (2013), the Liard Basin's Lower Besa River shale has an extremely high resource concentration of 319 Bcf/mi^2, more than double that of the Horn River Basin. Within the most highly prospective area of the Liard Basin, around and east of the Liard River, the risked shale gas-in-place (or total prospective resource) is approximately 526 Tcf, very similar to the Horn River Basin. Based on the basin's favourable mineralogy but complex structure, Advanced Resources International Inc. (2013) estimates that there is a "technically recoverable shale gas resource of 158 Tcf for the Liard Basin," while Ziff Energy Group (2013c) estimates it could exceed 140 Tcf.

43 KM LNG (2010, 5) identified that Apache's lands in the Horn River Basin hold and average of 110.3 Bcf/mi^2.

44 On the downside, Horn River Basin gas also has a high CO_2 content of approximately 12 per cent (BC Hydro 2013), leading to estimates of total "shrinkage" – the proportion of gaseous material extracted from a well that is lost during processing down from raw to sales gas – of 19 per cent (the remaining 7 per cent being attributed to fuel usage during extraction and processing), high by gas industry standards (KM LNG 2010).

Apache Corp. has suggested that 210 Tcf of gas-in-place may be located in its Liard Basin holdings alone (Oil and Gas Financial Journal 2012). Apache has a 100 per cent interest in a 430,000 acre lease position in the centre of the Liard Basin, with 54 Tcf of recoverable gas and 48 Tcf of marketable gas (Apache Corp. 2012; 2013). Nexen has a 128,000 acre (net) land position and 24 Tcf of prospective recoverable gas resource in Liard (Advanced Resources International Inc. 2013). A presentation from Apache Corp. (2013) suggests that infrastructure already exists for its Liard holdings to access gas pipelines, and alludes to access to major incremental infrastructure being developed by TCPL and Spectra. Apache Corp. (2012) indicated it needs $2.57 at the wellhead to make its Liard play commercially viable.

Overall, the Liard Basin remains relatively undeveloped (or "very immature," to use the gas sector language), with natural gas rights sales really only heating up starting in 2010. It's high prospectivity and very strong returns from some of (primarily Apache's) test wells make the Liard an immediate target for growth, however.

6.1.3 Cordova Embayment

The Cordova Embayment, covering an area of 4,290 km^2, is the smallest of the three primary FNFN shale gas basins. It is located in the extreme northeastern corner of B.C. This formation has a moderate resource concentration of 68 Bcf/mi^2 (Advanced Resources International Inc. 2013). Based on favourable mineralogy and other properties, the prospective area likely has risked gas-in-place values of 81 Tcf and a technically recoverable shale gas resource of approximately 20 Tcf (Advanced Resources International Inc. 2013). Steve Davis and Associates Ltd. (2011) suggests that the total original gas-in-place for the Cordova Embayment may be as high as 200 Tcf.

In terms of existing industrial activity, Nexen has acquired an 82,000-acre lease position in the Cordova Embayment and has drilled two vertical and two horizontal shale gas exploration wells. Nexen estimates a contingent resource of up to 5 Tcf for its lease position. PennWest Exploration and Mitsubishi have formed a joint venture to develop the estimated 5 to 7 Tcf of recoverable shale gas resources on their 170,000-acre (gross) lease area.

6.1.4 Montney Basin

The Montney Basin is another relatively recent entrant into WCSB gas production with shale/tight fracking starting in 2006. Despite the play's relative immaturity, it is already the largest producer of gas in B.C. today. Its production rates grew to 376 Mmcf/day in 2009 and 1.7 Bcf/day by 2012 (B.C. OGC 2013a). By 2011, more than 80 per cent of production was from 400 or more horizontal wells and cumulative production was more than 2.0 Tcf (BMO 2011). NEB et al. (2013) estimates the Montney produced more than 12 per cent of Canada's total 13.9 Bcf/day production.

The vast majority of the Montney Basin lies south of FNFN territory, although its northern-most extent is mapped into the Fontas area of FNFN territory south of Fort Nelson. The Montney Basin straddles the B.C./Alberta border, with substantial resources on both sides. A recent government study has estimated that Montney has the largest gas resources of any WCSB formation and one of the largest in the world (Daly 2013), at 449 Tcf of economically extractable natural gas (NEB et al. 2013). BMO (2011) estimates approximately 200–350 Bcf/mi^2 of gas-in-place in portions of the Montney.

Progress is a major player in the Montney. Redden (2012) refers to them as a pioneering operator, and they have since been taken over by Petronas Energy out of Malaysia, the proponent of the Pacific Northwest LNG facility in Prince Rupert. Overall, there were over 25 other operators in the Montney as of late 2012, including Encana, Talisman Energy/Sasol Ltd., Shell and PetroChina (Oil and Gas Financial Journal 2013).

6.1.5 Duvernay Formation

The Duvernay Formation is a highly immature (i.e., new and largely undeveloped) shale play in west-central Alberta. It is attractive in large part due to its rich natural gas liquids (NGLs), which increase well revenues through by-product extraction (Oil and Gas Financial Journal 2012). The area has been subject to a land rush since 2009 (BMO 2012).

Companies with strong ties to the Duvernay shale play as of late 2012 included Canadian Natural Resources Ltd. (500,000 acres), Encana (partner in some 253,000 acres – Suttles 2013), Talisman Energy (350,000 acres) and Chevron Corp. (220,000 acres). ExxonMobil Corp. (110,034 acres) and PetroChina Ltd. (Oil and Gas Financial Journal 2013) have also bought into the Duvernay.

This unconventional gas play is estimated to requie at least a half-decade of development time prior to becoming a major contributor to WCSB gas production (Hussain 2012). Early estimates (Ziff Energy Group 2013c) indicate 14 Tcf of currently marketable gas in the liquids rich portion of the play, but Alberta's Energy Resources Conservation Board is much more optimistic, estimating a total resource of 443 Tcf of gas along with strong NGLs and oil values (as reported in Suttles 2013). BMO (2012) is even more optimistic, with an estimate of a "liquids-rich gas window" in the Duvernay containing 750 Tcf of gas-in-place.

Table 7 summarizes available statistics on the five primary reserves of interest for this report, including the Horn River Basin, Liard Basin, Cordova Embayment, Montney Basin and Duvernay Formation. More details on factors contributing to the competitiveness of these different gas plays are discussed in Section 6.5.

There are some important limitations to the information base available for all these relatively immature or early production stage gas basins. First of all, given the inherent uncertainty and complexity of assessing the amount of resources hidden from view underground, different analysts will provide different estimates of the size of the resource. As a result, the numbers estimated in public documents are inconsistent and best reported in a range rather than a specific estimate. In addition, these resource estimates will tend to increase over time with more accurate estimates, as seen in the new Montney Basin numbers (NEB et al. 2013).

Overall, what is perhaps most distinctive about these WCSB shale and tight gas basins is that they are extremely large in gas in place and recoverable resource estimates, on par with any other shale resources calculated anywhere in the world to date. With the possible exception of Cordova Embayment, each alone, let alone all in combination, likely has enough gas in place to fuel B.C.'s LNG export requirements for decades. Ziff Energy Group (2013b) suggests that all of these shale and tight gas plays are relatively immature (meaning more than adequate feedstock is available) and relatively low cost, representing an abundance of low cost natural gas resources available in the WCSB to fuel the B.C. LNG sector.

This realization moves the discussion away from which of these basins *can* fuel the LNG sector, to which *will* preferentially fuel the B.C. LNG sector, and why.

Table 7: Summary of available statistics on primary WCSB natural gas reserves

	Horn River Basin	Liard Basin	Cordova Embayment	Montney Basin	Duvernay
Area (sq km)	11,500	9340 – 11,140	4290	+/- 25,000	+/- 10,000 (Alberta)
Gas Initially-in-place (Tcf)	144 – 820	125 – 526	81 – 200	80 – 700[a]	377-443
Resource density (Bcf/mi^2)	60-320	170-500	+/- 68	8-350	80 – 100
Marketable gas (Tcf)	60 – 170; best estimate is currently 78-120	31 – 158	20-68	+/- 449	Not available
Total gas produced to date	<1 Tcf	Not available Minimal	12 Bcf	1.5 to 3.5 Tcf	1.5 Bcf
Current volume output (2011–2012)	245 – 382 Mmcf/day	21 Mmcf/day (only one well reporting)	15 – 200 Mmcf/day	1,640 – 1,700 Mmcf/day	6 Mmcf/day
Wells operating (2012)	80 – 159[b]	3	21	>1,100	8-45
EUR/well	4.1 to 16 Bcf	Up to 18 Bcf	4.1 to 12 Bcf	2.9 to 9 Bcf	4.3 Bcf
Most active operators in the region	Apache Canada Ltd., Imperial Oil, Nexen, Quicksilver Resources	Apache, Nexen	Penn West Exploration Ltd, Mitsubishi Corporation, Nexen Inc.	Progress, Shell Murphy Oil Co, Talisman, Encana	Encana, Talisman, Chevron, ExxonMobil, Petro China

Notes: [a] Alberta's Energy Resources Conservation Board estimates are much higher than those of the NEB et al. (2013), at 2333 Tcf gas in place (reported in Hussain 2012).
[b] This data on operating wells is subject to high uncertainty. For example, Johnson (2009) identified 1,547 gas wells in the Horn River Basin, a five-fold increase since 2000. Many are conventional and many are not operating at the present time due to reservoir deplenishment or capping due to low gas prices. B.C. OGC (2013a) data indicates that as of the end of 2012, 328 wells had been drilled in the Horn River Basin and 26 in the Cordova Embayment targeting shale deposits.

Sources: Advanced Resources International Inc. (2013); Macquarie Research (2012b); BMO (2012); Apache Corp. (2013); Oil and Gas Financial Journal (2012); Suttles (2013); BMO (2011; 2012); NEB (2009); B.C. OGC (2013a); CERI (2012); B.C. MEM and NEB (2011); Adams (2013).

6.2 TRIANGULATION METHOD #1: CONTINUATION OF CURRENT FNFN GAS PRODUCTION PROPORTION

Using this method, it is assumed that the current proportion of total WCSB production sourced from FNFN territory will continue into an LNG export scenario. This approach assumes that FNFN gas production growth rates will be equal to that of other WCSB gas plays in the future and also contribute to LNG in the same proportion it currently contributes to the North American market.

It is worth noting at the outset that this assumption is very conservative and likely unrealistic. It assumes that all WCSB plays continue to maintain the current relative level of investment, maturity, size and ownership structures, making them attractive in consistent relative proportions to LNG exporters. In the case of FNFN territory, the plays are very large and very immature (only at the beginning of their productive lives), and tenure is tied to a variety of players who are in or want to get into vertical integration in the LNG sector (see Section 6.6). In addition, virtually all industry estimates indicate FNFN gas plays are likely to grow in importance in relation to B.C. and WCSB gas production over the next two decades (see Section 6.4). As a result, overreliance on this triangulation method is likely to significantly underestimate future production activity in FNFN territory.

Currently, the Horn River Basin is the only FNFN basin with any substantial gas production, and these rates are still low. Advanced Resources International Inc. (2013), using 2011 B.C. OGC data, indicated that Horn River Basin was producing 382 Mmcf/day, versus 1.4 Bcf/day from the B.C. portion of the Montney Basin. More recent estimates have actually seen slight reductions in Horn River while Montney continues to expand. Montney in B.C. produced +/-1.64 Bcf/day in 2012, while all gas from combined sources in FNFN territory dropped to an estimated 281 Mmcf/day in 2012 (B.C. OGC 2013a). This is due in large part to low gas prices that made additional production from FNFN territory commercially unviable. An illustration of the “Montney Advantage” (see Section 6.5) is that basin continued to grow in production in 2012 despite these same market conditions.

With total B.C. sales gas production at about 1.3 Tcf/year or 3.5 Bcf/day (CAPP 2012),[45] FNFN gas in 2012 fell slightly to eight per cent of total B.C. production. In terms of WCSB’s annual production of approximately 13-14 Bcf/day in 2012 and 2013, FNFN gas currently represents only about two per cent of production. These numbers increase only slightly if using 2011 production levels of +/-400 Mmcf/day, to 12 per cent of B.C. and three per cent of WCSB production.

While it is unrealistic to assume that the proportion of production in FNFN territory will remain unchanged over the next 25 years, a couple of factors make this current proportion estimate useful to consider. Firstly, it relies on existing data and makes a useful base case. Secondly, it identifies there is at least one play – Montney – which has a strong headstart over FNFN gas deposits, and would likely be first and preferentially tapped, especially by those vertically integrated LNG proponents that are have substantial holdings in the Montney formation (e.g., Progress/Petronas – see Section 6.6).

If the proportion of WCSB gas produced in FNFN territory were to remain unchanged over the next 25 years, and all WCSB regions were to contribute gas to the LNG supply chain, at the same proportion of their contribution to total production, FNFN territory could be expected to supply two to three per cent of the total volume of gas required by the B.C. LNG export sector.

45 With FNFN shales and Montney gas contributing about two Bcf/day in 2012, the remaining 1.5 Bcf/day was primarily from conventional gas wells, production from which is estimated to decline precipitously in the future.

6.3 TRIANGULATION METHOD #2: FNFN GAS-IN-PLACE PROPORTION

> *[B.C.] has over 1,300 Tcf of natural gas in place in just the Montney (700 Tcf) and Horn River (+600 Tcf). Recent developments in the Liard Basin and future potential of the Cordova Embayment will only serve to bolster this number in the future.* – Macquarie Research (2012a, 2)

While current gas production in FNFN territory is low, actual supply to future LNG facilities will likely be based more on the size of the remaining resource in the ground rather than current production levels. As discussed in Section 4, long-term decline in conventional gas production is expected to continue, and shale gas resources like those from the currently "immature" FNFN plays, which have cost and scale advantages over existing more mature gas plays and which are almost completely untapped,[46] will rise in importance. Macquarie Research (2012a, 5) notes that despite drilling drop offs in 2012 in the Horn River Basin, "early producers such as Encana and Nexen have delineated much of the play and established it as a viable supply source for west coast LNG."

Evidence from a variety of sources indicates that in terms of both gas-in-place and recoverable gas, gas basins in FNFN territory are extremely large.

- Advanced Resources International Inc. (2013) estimated that the three FNFN shale basins hold risked resources in place of 1137 Tcf and risked technically recoverable resource of 311 Tcf.
- B.C. MEM and NEB (2011) estimated 448 Tcf in place for Horn River, with an expected marketable shale gas of 78 Tcf.
- Ziff Energy Group (2012) estimated that 33 per cent of known total WCSB recoverable supply was in the Horn River Basin (18 per cent), Liard River Basin (12 per cent) and Cordova Embayment (3 per cent).
- Macquarie Research (2012b) estimated that as of mid–2012, Montney, Horn River and Liard had between 165 and 325 Tcf of recoverable natural gas, as follows:
  - Montney – 50 to 150 Tcf;
  - Horn River – 60 to 100 Tcf; and
  - Liard – 55-75 Tcf.[47]

These proportions have since been altered by a major new study of the Montney Basin released in November 2013 (NEB et al. 2013), which recalculated that the bulk of WCSB's ultimate marketable natural gas potential is in the Montney Formation, at 449 Tcf, or some 55 per cent of the known total WCSB ultimately marketable natural gas supply, versus 78 Tcf for the Horn River Basin. Overall, NEB et al. (2013) estimates that Alberta has 403 Tcf of ultimately marketable natural gas, while B.C. has 400 Tcf (Montney straddles the B.C./Alberta border). The remainder of the WCSB is limited to 17-18 Tcf total, for a total of approximately 821 Tcf, which indicates that the Horn River Basin has an estimated 9.5 per cent of the WCSB's marketable gas (78 of 821 Tcf).

While the NEB et al. (2013) study provided no estimate of gas resources in the Liard Basin and the Cordova Embayment, it is estimated that the Liard Basin has an ultimate resource similar to or greater than that of the Horn River Basin (see Apache Corp. 2012; 2013; U.S. EIA 2013). For example, while formal Canadian

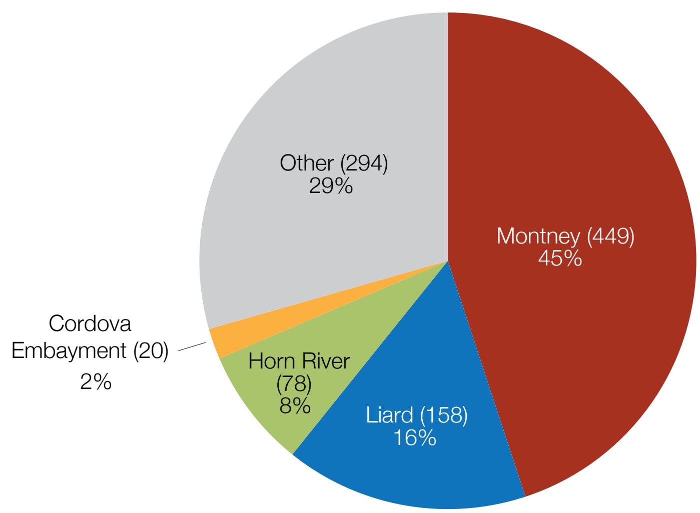
46 For example, Ziff Energy Group (2012) estimates that 260 of 261 Tcf of Horn River Basin original gas in place has not been extracted to date, and that Liard Basin and Cordova are equally intact. In contrast, the majority of WCSB's conventional gas reserves have already been extracted.

47 Liard estimates by Macquarie Research (2012b) consisted only of estimates from Apache and Nexen at that time.

government estimates have not been developed for the Liard Basin or Cordova Embayment to date, the U.S. EIA (2013) estimates that the Liard Basin holds 157.9 Tcf of recoverable[48] shale gas, more than double that of the median range estimate for the Horn River Basin, and the Cordova Embayment holds an additional 20.3 Tcf of recoverable gas. Firelight added these totals to existing government totals to come up with a total estimate of ultimate recoverable gas in the WCSB of 999 Tcf (821 + 158 +20).

Given currently available information about WCSB gas resources, the author estimates that the three FNFN basins account for up to 256 Tcf out of a WCSB total of 999 Tcf of recoverable gas, or 25.5 per cent (Figure 7).[49] **However, the author has also adopted a low range estimate of recoverable gas in line with low estimates from a variety of sources as well, at 110 Tcf for the three basins, or 13 per cent of recoverable gas in the WCSB.**[50]

Figure 7: Marketable gas potential in WCSB (Tcf)



Regardless of the variability evident in different gas-in-place and marketable gas estimates, from a potential supply perspective FNFN gas is strongly situated to be an important part of future LNG supply. Different estimates identified above (including in Table 7) indicate marketable gas values for the three FNFN basins between 110 and 400 Tcf, from original gas-in-place values between 350 and 1500 Tcf. There is sufficient marketable gas in FNFN territory to provide substantial support to even the highest level of potential B.C. LNG export growth of 144.5 mtpa (current NEB export licence approvals and applications). This would require 18.9 Bcf/

48 Differences exist between NEB et al. (2013) and U.S. EIA (2013) criteria. NEB et al. (2013) define "marketable" as the volume of in-place petroleum that is recoverable under foreseeable economic and technological conditions. U.S. EIA (2013) defines "technically recoverable" as volumes of natural gas that can be produced with current technology. The big difference between the two is the former's inclusion of "foreseeable economic conditions," while economic is not a factor in the latter. The author recognizes heightened uncertainty in this calculation due to these definitional differences between Montney/Horn/rest of WCSB and Liard/Cordova. We have used the NEB's terminology in our final estimations.

49 Rapid shifts in estimated proportions are indicative of the fluctuating nature of gas resource estimates. Additional government and industry research on the Liard Basin, for example, would likely increase the FNFN gas-in-place proportion while detailed government predictions of the gas resources of the Duvernay Formation would likely shrink the FNFN proportion.

50 The author calculated the low range proportion by using the lower range recoverable gas estimates in Table 6 for Horn River, Liard and Cordova (approximately 110 Tcf) and dividing this amount by the NEB et al (2013) estimate of recoverable WCSB gas resources, minus the 78 Tcf from the Horn River Basin that was included in that estimate (821-78=743), and with the 110 Tcf low end estimate for the three FNFN basins added back in (743+110=853). 110 of 853 Tcf equals approximately 13 per cent.

day or 6.9 Tcf/yr, equivalent to about 35 years of this study's high range scenario for marketable gas in FNFN territory (256 Tcf).

"Gas-in-place" estimates need to be treated with caution and should not be used as the sole determining factor of future basin-by-basin production to meet B.C. LNG export demand. Numbers are always changing as new studies are completed[51] and technology advances. For the purposes of this study, the key take away point is that the significant proportion of total WCSB gas-in-place in FNFN territory is indicative that future extraction from FNFN territory can increase relative to WCSB totals, in particular in relation to declining conventional supplies. Declining reserves should not be a factor for decades in any of the unconventional plays being considered, and therefore are unlikely to be a primary deciding factor. The author agrees with Redden (2012, 68) that:

> *While 2012 drilling plans are mixed… data provided by both the Ministry [BCMEM] and the most active companies in both the Horn River and Montney plays suggest Kitimat [LNG] will not be lacking for raw material when the time comes.*

Gas resources in place are thus a necessary but in this case not sufficient indicator of likely future gas extraction rates or duration in the WCSB. Huge unconventional plays have removed any concerns about resource constraints, according to Lewis (2013), who noted that conventional resources underpinning the Mackenzie Valley pipeline totalling six Tcf are dwarfed now by WCSB unconventional gas resources 100 times that amount.

In the absence of any realistic resource constraints, the comparative competitive positions of different gas basins and assets of LNG players in each may be more critical factors, as discussed further in Sections 6.5 and 6.6 below.

6.4 TRIANGULATION METHOD #3: PREDICTIONS OF FUTURE BASIN-BY-BASIN PRODUCTION LEVELS

> *Is there enough natural gas in BC to support Discovery LNG and other LNG facilities in BC? In the Horn River Basin, where Discovery LNG would potentially receive the majority of its natural gas from, some analysts predict as much as 150 trillion cubic feet (Tcf) of unconventional gas resources. As all of Canada currently only produces 6 Tcf annually, there is easily enough to support Discovery LNG and other B.C. LNG facilities for many years.*[52]

There have been a large number of recent publicly-released supply and demand forecasts for North American and Canadian gas, especially in association with NEB LNG export licence applications (e.g., Ziff Energy Group 2012; 2013a; 2013b; Priddle 2013a; 2013b). However, while some of these forecasts have included potential B.C. LNG exports as part of their estimations, none have broken down their estimations by individual basins.[53] As a result, there is no publicly available analysis of future WCSB production comparing likely production on a basin-by-basin basis. In addition, this study located few predictions of likely future growth by basin over the past two years (2012 and 2013), meaning that most available predictions for growth were from a time prior to the scope of the proposed B.C. LNG sector being fully revealed. As a result, there is minimal public information available on a key question – what range of production increases are likely in FNFN territory in an LNG export scenario?

51 The discussion above on the implications of the new November 2013 Montney report (NEB et al. 2013) is a good example.

52 discoverylng.com/project-details/faq/

53 Some analysts (e.g., Ziff Energy Group) hold proprietary basin-by-basin cost data and possibly basin-by-basin production estimates not available within the cost confines of this study.

In lieu of this information, the author reviewed publicly available forecasts, most of them generated prior to the recent "LNG revolution" in B.C., to identify expected trends for key WCSB basins. It is assumed for the purpose of this triangulation method that the relative attractiveness that drove the earlier growth estimates for FNFN gas has not changed, even if the market into which the gas is to be sold has changed from a North American focus to a combined North American-Asian LNG focus. In other words, if FNFN territory basins were expected to grow exponentially to fuel North American gas needs, the factors that led to these previous growth estimates are assumed to be the same in a future where LNG becomes a prime mover for the sector.

Recent estimates of future growth in gas production in FNFN territory have been exponential in nature. Most have focused on the Horn River Basin, the first FNFN shale basin to see heavy unconventional exploration and development activities. For example:

- The National Energy Board (NEB 2011) estimated Horn River Basin production alone will grow to 4.0 Bcf/day by 2035, a ten-fold increase from 2011.
- TCPL subsidiary Nova Gas Transmission Ltd. (2011) estimated growth to 3.8 Bcf/day by 2025 between Horn River Basin and Cordova, a similar nearly ten-fold increase.
- Wood Mackenzie (2011) estimated Horn River Basin would grow from 200 Mmcf/day in 2010 to 4.6 Bcf/day in 2033 (a more than twenty-fold increase), and exceed Montney (4.0) in annual production rates by that time.[54] By 2033, Wood Mackenzie estimated Horn River Basin would be producing 28 per cent of WCSB's total production of 16.6 Bcf/d.
- The Canadian Association of Petroleum Producers (CAPP 2012; 2010) predicted that Horn River Basin production would grow by six to ten-fold to two Bcf/day by 2020.
- BC Hydro (2013) developed three gas production scenarios for the Horn River Basin from 2014 to 2059. The study explicitly recognized potential for LNG exports to be one of the drivers of growth, but did not attribute a specific proportion of modelled growth to LNG. The results are shown in Table 8.[55]

Table 8: BC Hydro Horn River Basin / Fort Nelson Region natural gas production scenarios

BC Hydro (2013) Horn River Basin Scenario	2018 production	2038 production	Comments
BC Hydro Low	600 Mmcf/day	2.65 Bcf/day	Assumes 300 Mmcf/day by 2014
BC Hydro Mid	1.75 Bcf/day	4.9 Bcf/day	Assumes 700 Mmcf/day by 2014
BC Hydro High	3.3 Bcf/day	6.3 Bcf/day	Assumes 1.1. Bcf/day by 2014

54 These estimates grew rapidly in 2011 and 2012; in 2010, Spectra Energy (in OnPoint Consulting 2010) was still predicting only 1.5 Bcf/day by 2020 from the Horn River Basin. It is also worth noting that the Liard Basin is not even mentioned in any of the estimates discussed here, with the possible exception of BC Hydro's 2013 estimates.

55 It is not clear whether this includes all three basins or just Horn River Basin. The document states that this is the "Fort Nelson/HRB region," so conservatively Firelight has considered it to include all three FNFN shale basins.

In general, there has been an expectation in these published estimates that the attractiveness of the Horn River Basin would see growth in production at least six-fold and likely ten-fold over the next decade to 25 years, and potentially as much as twenty-fold.

This optimism must now be tempered by two factors:

1. Estimated extraction growth rates from the Horn River Basin and other FNFN basins have not come to fruition during the early parts of these forecast periods. For example, only BC Hydro's low estimate of 2014 is likely to be exceeded, and Nova Gas Transmission Ltd. (2011) had estimated combined Horn River and Cordova production of 1.13 Bcf/day for 2012/13, some four times the actual production rate that occurred.

2. Increasingly optimistic estimates of gas-in-place and recoverable resources in competing basins outside FNFN territory, especially Montney and Duvernay, in the interim.

Notwithstanding these limiting factors, there have as yet been no estimates of future extraction rates put forward to contradict the studies noted above. The current data available indicates that FNFN gas is expected to play an increasing role in WCSB production levels over the next 25 years. Consider for example that Ziff Energy Group (2012) predicts production growth in the WCSB from 14.5 Bcf/day in 2011 (down to 13.9 Bcf/day in 2012) to 17.3 Bcf/day in 2045. This estimate is about in the middle of future WCSB production estimates, which range from about 16 Bcf/day up to as high as 20 Bcf/day by 2045. If FNFN gas basins are producing 3.8 to 4.9 Bcf/day of this range,[56] that would represent between 19 and 30 per cent of WCSB totals. **The findings suggest that, if the proportion of LNG-induced gas extraction occurs at the same rate as available public estimates of future WCSB gas production proportions from FNFN territory, between 19 and 30 per cent would come from FNFN territory.**

The findings suggest that, if the proportion of LNG-induced gas extraction occurs at the same rate as available public estimates of future WCSB gas production proportions from FNFN territory, between 19 and 30 per cent would come from FNFN territory.

If FNFN gas was to continue supplying only the North American market, there is every reason to believe that these prior growth estimates are too high given recent supply and demand shifts. Recent U.S. shale gas production growth and low North American gas prices have been pushing Canadian gas out of the market, and the distant and relatively higher cost (compared to Montney) and lower value (dry gas) FNFN basins are especially vulnerable. If, however, an LNG export market emerges, there is reason to suspect strong growth in FNFN gas production, similar to if slightly lower than these previous estimates. After all, it was the geological attractiveness of the Horn River Basin (and later, of the Liard Basin) that saw these ten-fold increases forecast. This growth depended on a gas price that justified development. LNG exports may well provide the price premium that "monetizes" gas in FNFN territory.

56 This 3.8 to 4.9 Bcf/day range is based on available estimates of FNFN territory gas production from 2045 or the latest date before that, from the previous list of estimates. These amounts were then divided by total estimated WCSB production rates by 2045. Note that this estimate conservatively ignores that these estimates were largely limited to the Horn River Basin, that these estimates were largely for time periods well before 2045, and BC Hydro's high end estimate from Table 8.

6.5 TRIANGULATION METHOD #4: CONSIDERATION OF COMPARATIVE ADVANTAGES OF WCSB BASINS

To better understand basin-by-basin production futures, it is helpful to examine some of the factors that drive comparative advantages of the different WCSB gas basins. The author examined information available about the comparative advantages of different WCSB basins which may increase or decrease the likely proportion of LNG to come from FNFN territory accordingly. Factors that may lead to differences in competitiveness on a basin-by-basin level include:

- **ESTIMATED ULTIMATE RECOVERY (EUR) PER WELL** – This measure is closely linked to resource density. The higher the EUR, the larger the amount of gas produced per well, and the greater the potential for economies of scale and lower per-unit production cost.
- **DISTANCE TO MARKET** – Generally speaking, the greater the distance that the gas must travel to reach the market, the higher the cost. The distance to market issue is not a huge factor for WCSB gas, all of which is in relatively close proximity to the B.C. coast. However, Macquarie Research (2012b) suggests Horn River may face incrementally higher pipeline tolls than Montney.
- **PROXIMITY TO EXISTING GAS TRANSPORTATION AND INFRASTRUCTURE** – Available infrastructure in place in the form of gas plants and pipelines could transport about 1.05 Bcf/day per day from FNFN territory. This infrastructure will have to expand to accommodate future growth. In contrast, Montney has a much higher existing sales gas refining capacity in addition to being the primary tie-in point for the majority of currently proposed LNG-dedicated pipelines (see Figure 5).
- **PRESENCE OF NATURAL GAS LIQUIDS (NGLS)** – Virtually all FNFN gas is "dry" gas, meaning it contains minimal NGLs. This puts it at a disadvantage against "wet" gas deposits with large amounts of other products such as ethane and propane, which can be separated out and sold for added value (Mirski and Coad 2013). Encana has recently made a major shift to NGL-rich gas deposits and out of FNFN territory, retrenching into Montney and Duvernay holdings (Tait 2013).
- **AVAILABILITY OF SKILLED LABOUR AND EQUIPMENT** – The remote northeastern B.C. gas basins are at a disadvantage that may only get worse with increased construction and development of LNG facilities, pipelines and gas facilities at points further south such as the Montney, Duvernay, and central and coastal B.C. (Macquarie Research 2012a). In general, it is recognized that "competition for experienced construction workers in northern B.C. is expected to be fierce, given the significant investment projected for natural gas and other capital projects in the area" (Petroleum Human Resources Council of Canada 2013, 7).
- **AMOUNT OF CO_2 IN GAS** – FNFN gas is relatively high in CO_2 (as high as 12 per cent – ($S\&T^2$) Consultants Inc., 2010). This is a disadvantage versus Montney and other plays which have lower CO_2 content (Montney averages about one per cent), in large part because a substantial percentage of the overall product produced is not gas (CO_2 is considered an "impurity").[57]

57 B.C.'s Climate Action Secretariat uses average CO_2 concentrations of 0.8 per cent, 5 per cent, and 8 to 12 per cent for the Montney, conventional and Horn River basins, respectively. (pers. Comm. between FNFN Lands Department and B.C. Climate Action Secretariat, October 2013).

- **DEVELOPMENT COST DIFFERENTIALS** – A variety of factors including infrastructure, distance from major supply centres, climate, among others, and water needs contribute to these cost differences. (S&T^2) Consultants Inc. (2010) estimated average horizontal well costs in the Horn River Basin of $7 to $10 million,[58] versus $5 to $8 million in Montney.

- **MATURITY OF PLAYS, ESPECIALLY DIMINISHING RETURNS OVER TIME** – As mentioned in Section 6.3 above, this is unlikely to be an issue for any WCSB unconventional plays for many years. On the contrary, conventional gas plays are on the decline due to longer production lives to date diminishing their smaller resource pools in addition to their lack of high EUR per well, making them higher cost per unit of production than unconventional sources.[59]

Table 9 identifies, based on the author's understanding from publicly available documents, relative competitive advantages of the different WCSB plays likely to contribute to a B.C. LNG export sector. Arrows pointing up indicate an area of strength for that basin, an equals sign indicates neither an advantage nor a disadvantage, and a downward pointing arrow indicates a disadvantage. Note that the criteria are not weighted in this table, meaning no criterion is automatically deemed to be more important to business decisions than any other. Please note as well that these advantages and disadvantages are primarily based on subjective comparison between the basins themselves and not against a larger pool of Canadian (e.g., conventional plays) or U.S. shale plays. It is this inter-WCSB comparison that is most important to this study's primary question of proportion of WCSB LNG export feedstock likely to be extracted from FNFN territory.

Table 9: Subjective analysis of comparative advantages and disadvantages of WCSB basins

	Montney	Horn River	Liard	Cordova	Duvernay
EUR/well	=	↑	↑	=	Unknown
Cost per unit of production	↑	↓	Unknown	Unknown	Unknown
Distance to market	↑ or =	=	=	=	=
Presence of Natural Gas Liquids (NGLs)	↑	↓	↓	↓	↑
Total recoverable resource (Section 6.3)	↑	↑	↑	↓	Unknown
Current production and infrastructure capacity	↑	=	↓	↓	↓
Availability of labour	= or ↑	= or ↓	↓	↓	=
CO_2 and other impurities – "shrinkage" level of raw gas	↑	↓	↓	↓	Unknown
Level of vertical integration into LNG sector (Section 6.6)	↑	↑	↑	↑ or =	↑

58 Macquarie Research (2012a) suggests this number can reach $20 million per well in Horn River.

59 Priddle (2013a, 19) notes that "some [unconventional] plays such as Montney and Horn River are lower cost than the Western Canada average [primarily made up of conventional plays], and production there can be expected to increase."

Table 9 indicates a “Montney Advantage” – a term actually used by industry analysts such as Macquarie Research (2012a; 2012b). According to publicly available evidence, the Montney Basin is slightly better situated geographically, has a larger currently estimated resource base, has better infrastructure in pipelines and gas plants, and has higher level of NGLs and lower levels of CO_2 in its gas deposits.

As a result of these advantages, the majority of industry analysts agree that production development in the Montney Basin will surpass that in other basins in the short-to-medium term. Macquarie Research (2012b, 59) estimates “the Montney tight gas/shale play provides a lower cost option for LNG players than the Horn River,” with higher NGL yields, better infrastructure and associated cheaper well costs. Macquarie Research (2012a) estimates that Montney has about a $1.44 cost advantage over Horn River per 1000 cubic feet of gas delivered to LNG export facilities.[60] While this means much less in the context of LNG for export to Asia than it would in domestic markets (LNG prices are much higher overseas and may be able to offset a production price difference that would simply shut out a play from the North American market), it remains a relevant advantage that is likely to influence development intensity between the two basins, to Montney’s advantage.

In addition, the very immature Duvernay play in central and western Alberta has wet gas and is still fairly close to the B.C. coast and potential LNG terminals. Imperial/Exxon and Chevron PetroChina, LNG hopefuls, are recent investors, and the play is being developed quickly.

Most industry analysts focus on the total production cost differential as the key factor making Montney the number one unconventional play in Canada. According to Hussain (2012), Montney’s mix of gas and NGLs make it economical at $2.50 per thousand cubic feet of gas, lower than Duvernay’s $3.20 and Horn River’s $4.00,[61] thus:

> *The Duvernay has also been gaining ground over Horn River. The dry-gas deposit… was seen at the most likely beneficiary of Canada’s LNG plans given its proximity to the West Coast, but is now seen out of favour at $4 per Mmcf breakeven costs.*

Other potential disadvantages for FNFN shale basins include “a short drilling season, lack of existing infrastructure (pipelines and roadways), produced carbon dioxide, and emerging water issues” (Walden and Walden, 2012, 9).

There are a couple of critical insights that temper these potential comparative disadvantages for FNFN basins. First of all, rapid growth is modelled by government, industry and industry analysts in both the Montney and FNFN unconventional plays into the future (as per Section 6.4 above), despite claims of a “Montney Advantage.” Second, it is very difficult to predict a specific proportion of future gas supply by basin based on comparative advantage alone. One reason for this is that there are so many factors to consider. Another is that different companies will weight factors differently, depending on their tenure position in different basins and LNG plans (see Section 6.6 below). Finally, average costs per well, while higher in FNFN territory, may in the future be offset by the potentially much higher EUR of FNFN territory wells, which may rapidly reduce production costs per unit of production as the play matures.

Nonetheless, in general, the “Montney Advantage” should not be discounted in relation to future gas production proportions within the WCSB. Montney has a variety of current advantages over the FNFN basins.

60 Macquarie Research (2012a) estimates a break even price for LNG, including integrated upstream (wellhead) and LNG facility costs, at $8.60 per thousand cubic feet of gas from Montney, versus $10.04 for Horn River gas.

61 Suttles (2013) suggests an even lower “supply cost” in Montney of $1.50-$2.20 per thousand cubic feet of gas. However, other estimates such as that by BMO (2011), see higher break even prices for Montney ($2.90/GJ) and relatively similar cost for Horn River and Cordova Embayment (both at $3.05).

It is difficult to estimate based on the multitude of factors that affect basin competitiveness just how much the “Montney Advantage” creates a “discounting” of the likely proportion of LNG export gas supply likely to come from basins within FNFN territory. **The evidence suggests, however, that if this basin-by-basin competitiveness was the primary factor, there would be a reduction in the expected proportion of LNG sourced from FNFN territory due to prioritization of Montney deposits.**

Primary factors influencing this “discounting” include:

a) The approximately 10 to 12 per cent higher “shrinkage” rate for FNFN gas versus Montney and other WCSB gas sources;[62] and

b) The approximately 15 per cent price premium estimated for break-even costs for LNG facilities using FNFN gas identified by Macquarie Research (2012a).

Taken in combination, these factors contribute to a competitive disadvantage for FNFN basins versus, in particular, the Montney Basin at this time. A producer with interests in both basins may see a current cost differential per unit of sales gas of 25 per cent or greater and prioritize development of Montney holdings over those in FNFN territory.

The author suggests these competitive disadvantages of FNFN shale gas versus other unconventional sources in the WCSB will likely reduce the proportion of LNG feedstock sources from FNFN territory.

Other potential competitive differences exist between FNFN gas basins and some of the other potential WCSB sources of supply, that are more difficult to estimate quantitative differences for. They include decreased by-product value potential due to the lack of NGLs in the dry gas in FNFN territory, and increased cost factors associated with lack of current infrastructure to move FNFN territory gas to the LNG facilities. Average costs per well, while higher in FNFN territory, are offset by the potentially higher EUR of FNFN territory wells (see Table 7 on page 51).

The author suggests these competitive disadvantages of FNFN shale gas versus other unconventional sources in the WCSB will likely reduce the proportion of LNG feedstock sources from FNFN territory, at least in the short term. In the absence of quantitative data for some of these disadvantages, this criteria is not assessed quantitatively. Rather, it will be discussed further in Section 6.7 when finalizing the range of scenarios.

An additional critical factor that emerges in relation to the prioritization of supply from particular basins is the level of vertical integration between downstream LNG facilities and upstream gas plays. This is discussed in section 6.6 below.

62 “Shrinkage” refers to the amount of material removed from the ground that is lost in subsequent processing from raw to sales gas. This can include water, CO_2, and other “impurities. FNFN gas’ high CO_2 content is the primary factor increasing its shrinkage rate beyond that from other WCSB formations (BC Hydro 2013).

6.6 TRIANGULATION METHOD #5:
TENURE IN FNFN TERRITORY OF COMPANIES SEEKING LNG VERTICAL INTEGRATION

> *There is also an option to connect Liard to the LNG market. This is a tremendous resource that will be important for Apache in the future.* – John Bedingford, Apache Corp., in Oil and Gas Financial Journal (2012)

Some of the strongest indicators of the actual amount of LNG demand likely to be sourced from FNFN territory emerge by examining who has tenure in the area, and their links to the fledgling B.C. LNG export sector. If LNG was a fluid, perfectly competitive market, the extraction would only be of the cheapest gas. But it's a non-fluid market dominated by a few key players who have the capacity to finance, build and run massive and capital intensive LNG facilities, and what matters to them as well is the location of their holdings and security of supply for them and those Asian interests they are contracted to sell LNG to.

Security of supply is thus an important consideration for LNG facilities. This is one reason there has tended to be a strong preference for vertically integrated production systems in this sector (Macquarie Research 2012a). As noted by PFC Energy (2012, 5):

> *Joint ventures between buyers and sellers have become increasingly popular, as this structure provides buyers with greater supply security and allows sellers to more easily monetize their gas. The merging of the upstream and downstream segments of the LNG value chain fosters enduring relationships between buyers and sellers to the benefit of the project.*

In such a system, the LNG facility receives gas from its own upstream facilities and therefore does not rely on external companies to make its operations work. This type of "equity supply" through control of upstream resources may be preferable to the other options of third-party supply through open market purchases or bilateral gas supply contracts of various lengths and volumes (Priddle 2013b). This is especially true in cases where the eventual end user prefers longer term contracts, as Poten & Partners (2010) suggest is the case for Asian LNG purchasers.

The following companies with links to proposed LNG facilities have holdings in FNFN territory:

- **APACHE AND CHEVRON** (Kitimat LNG): The joint venture partners hold 640,000+ acres in the Horn River and Liard Basins (Kitimat LNG, 2013). Most of the production growth to date has been in the Horn River, with estimated potential of 9-16 Tcf (Redden 2012). Recently, however, Apache has seen strong returns from its burgeoning Liard play, where it has estimated some 48 Tcf of ultimately recoverable gas (Apache Corp. 2012; 2013). Chevron, a major global LNG player, bought out Apache's previous partners Encana and EOG Resources Ltd. in 2012 (Vanderklippe 2012). The Kitimat LNG website indicates that "feed natural gas will come from Apache's Horn River and Liard fields," and cites "approximately 19 trillion cubic feet of combined marketable/technically recoverable natural gas resources."[63] Poten & Partners (2010, 16) identified one of the strengths of the Kitimat LNG facility even before global giant Chevron bought in as "equity partners who are also large producers who have committed to supplying the LNG project from their corporate supply pools… throughout the Western Canada Sedimentary Basin." Apache Corp. (2013)

63 kitimatlngfacility.com

identifies that the Kitimat LNG Project "monetizes" an extremely large 50 Tcf of gas, all of it in FNFN territory, and has made the link between its Liard holdings and the Kitimat LNG Project explicit:

> *As for drilling plans, the pace of development at Liard will be steady and likely further refined by how quickly the Kitimat LNG project takes shape.*

- **IMPERIAL OIL LTD. / EXXONMOBIL:** Imperial Oil and ExxonMobil are the co-proponents of WCC LNG Canada, a large (30 mtpa) but as yet unlocated LNG proposal on the B.C. coast. While Imperial/Exxon have strong holdings in FNFN territory, they have also expanded into both Montney and Duvernay with the purchase of Celtic Exploration Ltd. (Hussain 2012). The Proponents indicate they plan to use a combination of their "substantive" proprietary WCSB gas resources and gas obtained through commercial supply arrangements through a variety of mechanisms as feedstock (WCC LNG Ltd. 2013, 7), noting:

  > *The Project Proponents hold one of the largest land positions in the Horn River shale gas play in Northeast British Columbia with more than 340,000 combined net acres, and commenced early pilot production in late 2012.*[64]

- **NEXEN/CNOOC[65] AND INPEX** (Aurora LNG): The partners in the proposed Aurora LNG Project hold approximately 300,000 acres of shale gas resource in Liard, Horn River and Cordova (Aurora Liquefied Natural Gas Ltd. 2013). Nexen holds 90,000 acres in Dilly Creek area of the Horn River Basin, where its production is expected to increase from 50 Mmcf/d to 175 Mmcf/d in 2014 (Redden 2012). The Nexen/Inpex/JGC joint venture's shale gas holdings in FNFN territory has values in excess of 38 Tcf (15 in Horn River and Cordova combined, and 23 in Liard), making "LNG export…a viable option for maximizing the value of Nexen's shale gas resource" – Nexen 2013).[66] It is worth noting that the Aurora Project makes no reference in its NEB Export Licence Application (Aurora Liquefied Natural Gas Ltd. 2013) of the use of any other resources than its FNFN territorial holdings as LNG feedstock, and planned more than $200 million worth of work in the Liard Basin alone in 2013. The joint venture's commitment to FNFN territory is strong and strategic (Aurora Liquefied Natural Gas Ltd. 2013, 6):

  > *Nexen and IGBC [INPEX]'s diversified portfolio of shale gas assets in northeast British Columbia allows them to address a key project risk of production deliverability inherent in any LNG project through a prudent approach to developing secured assets to fulfill long-term supply commitments.*

- **MITSUBISHI AND KOGAS** (LNG Canada): Mitsubishi and Kogas are partners with Shell and PetroChina in the proposed LNG Canada facility in Kitimat (LNG Canada Development Inc. 2012). In September 2010, Penn West Energy Trust formed a 50-50 joint venture with Mitsubishi to develop Penn West's shale gas assets in the Cordova Embayment area and certain of its conventional gas assets in the Wildboy area of northeastern British Columbia. Mitsubishi's total acquisition cost with respect to this joint venture was approximately $450 million.[67] Mitsubishi also has a 40 per cent interest in the Montney Cutbank Ridge Partnership with Encana (Suttles 2013). Kogas has identified holdings in the FNFN territory as well (LNG Canada Development Inc. 2013). Macquarie Research (2012b) suggest a strong possibility that LNG Canada will seek additional acquisitions of upstream resources to increase their Canadian corporate reserves.

64 WCC LNG Ltd. (2013) indicates its parent companies also hold 545,000 net acres in Montney shale and 104,000 net acres in the Duvernay shale.

65 Nexen was recently acquired by the Chinese National Offshore Oil Company (CNOOC) for approximately $15 billion (as reported in Walden and Walden 2012).

66 See also nexeninc.com/en/AboutUs/MediaCentre/NewsReleases/News/Release.aspx?year=2013&release_id=135199

67 From http://mergersandacquisitionreviewcom.blogspot.ca/2011/03/international-companies-affinity.html

- **QUICKSILVER:** This company holds 130,000 acres in the northern portion of the Horn River Basin, estimated to hold 10 Tcf of recoverable gas. Quicksilver put four wells into production on 2010, and planned to put five more in 2011 (Redden 2012). Quicksilver has since proposed and received B.C. government permissions for its Fortune Creek Gas Plant, which is designed to refine approximately 600 Mmcf/day of raw gas to sales gas. The Proponent is linked to the Discovery LNG Project, which has yet to be proposed in detail as of the writing of this report.

Table 10 shows some of the players with tenure in FNFN territory and associated reserves (in Tcf) estimated for those players on a basin-by-basin basis. It is worth noting that the majority who are in FNFN territory are ***not*** in Montney, where indications are there is minimal land left available for leasing. In other words, companies like Apache, Nexen/INPEX, and Quicksilver are wedded to and heavily or completely reliant upon their holdings in FNFN territory if they are seeking to enter into the upstream supply of natural gas to the B.C. LNG export sector.

Table 10: Sample contingent and prospective gas resources by player and basin

Company	Horn River (contingent Tcf)	Liard (prospective Tcf)	Cordova (contingent Tcf)	Montney (contingent Tcf)
Apache	9.2	48	0	0
Nexen	5.0	13	3	0
EOG	6.9 (now Chevron)	0	0	0
Encana	4.3 (now Chevron)	0	0	8.1
Quicksilver Resources	10	0	0	
TOTALS	35.4	61	3	8.1

Notes and sources: This data was as of September 2012, according to Macquarie Research (2012a). Only companies noted to have gas interests in FNFN territory are included in this list. Note that while these companies had very little interest in Montney, many other players, like Talisman and Petronas, do.

Other companies such as AltaGas/Idemitsu, are currently more reliant on a "mixture of gas purchase contracts made directly with other resource holders and supply through transactions made at market hubs" (Triton LNG 2013, 4). Companies like British Gas (Prince Rupert LNG), Shell (LNG Canada), and ExxonMobil (WCC LNG) also plan to "top-up corporate gas reserves with purchases from the market" (Lewis 2013).

The implications for FNFN territory of vertical integration depends entirely on which LNG projects actually proceed. Different industry analysts have pegged different "front runners" but it remains highly uncertain at this time which proposed LNG projects will proceed. One industry analyst (National Bank 2013) suggests that by 2021 some 6500 gas wells may be required to supply the demand of four major B.C. LNG facilities, each of which has a different type of integration into FNFN territory at the present time:

1. Kitimat LNG – strongly linked to FNFN territory
2. LNG Canada – moderately linked to FNFN territory
3. Prince Rupert LNG – n/a (Proponent does not have ownership stakes in any WCSB plays)
4. Pacific Northwest LNG – weak or no links to FNFN territory

Reflecting the high uncertainty about which projects will proceed and when, another industry analyst (Macquarie Research 2012a) alternatively estimated that LNG Canada would be the first producer, followed by Pacific Northwest LNG.

There is inadequate information to suggest which LNG projects are most likely to proceed and in what order. Therefore, this study has adopted a wide range of possible probabilities. **If there is minimal vertical integration into FNFN territory of LNG projects that proceed (e.g., Progress Pacific Northwest), the amount of LNG-induced demand attributable to FNFN territory may be very low (e.g., +/- five per cent). If, however, the LNG projects have high FNFN territorial holdings, there is reason to expect some projects will source 50 to 100 per cent of their gas from their own holdings in FNFN territory (e.g., Apache/Chevron and Nexen/INPEX/JGC). With it impossible to conclude with confidence which of the currently proposed LNG projects will proceed, this report has adopted a 5 to 50 per cent range of supply FNFN territory to reflect this uncertainty.**

The author suggests this variable may be both the most important one and the one with the highest range of variability, given the high degree of uncertainty as to which LNG projects will actually proceed. The critical nature of vertical integration links into FNFN territory cannot be overestimated. For example, if the Aurora and Kitimat LNG projects were to proceed, the deep vertical integration planned by the proponents could see as much as 4.4 Bcf/day come from FNFN territory (3.1 Bcf from Nexen and its partners' holdings to feed Aurora and 1.3 Bcf from Apache and Chevron's holdings for Kitimat), well above this study's highest estimate of total LNG-induced gas extraction from FNFN territory of 2.68 Bcf/day (see Section 7 below). While 100 per cent vertical sourcing is unlikely for any project, the use of dedicated single-project pipelines and the obvious advantage of controlling security of supply is indicative that some projects aim to be primarily own-sourced.

A Vertical Integration Example – Apache's Liard Development Model and the Kitimat LNG Project

Kitimat LNG is one example of the potential implications of LNG vertical integration for extraction from FNFN territory.

Apache Corp. (2012; 2013) has reported a development model for its holding in the Liard Basin alone (Apache also has significant holding of 220,000 hectares in the Horn River Basin to go along with its over 400,000 hectares in the Liard Basin), that would see the production of 48 Tcf, or approximately an average of 1.92 Tcf/year. This is equivalent to 5.26 Bcf/day if measured over 25 years. Apache's development plan calls for 61 multi-well pads with 731 wells from Liard (Apache Corp. 2013). The gas needs to be sold into either the North American market, the Asian LNG market, or a mixture of both.

If all of that gas would go to LNG exports, keeping in mind that Apache has an ownership stake with Chevron in the Kitimat LNG Project, this gas extraction rate would cover between just under 50 per cent and over 100 per cent of the range of estimates of LNG-induced extraction from the WCSB identified in Section 5 (4.9 to 10.7 Bcf/day). If only half of the gas went to LNG, that would still be over 2.6 Bcf/day, or between 24 and 53 per cent of the required gas estimated to fuel the B.C. LNG export sector. As the Kitimat LNG Project requires only 1.3 Bcf/day even at full production of 10 mtpa of LNG, Apache's Liard holdings could easily fuel the entire facility with room to spare.

And the commitment to use its own holdings is strong in this Apache/Chevron joint venture. Hamilton (2012) suggests that Apache's Liard Basin find "is estimated in itself to justify doubling the size of the Kitimat terminal [to 10 mtpa]."

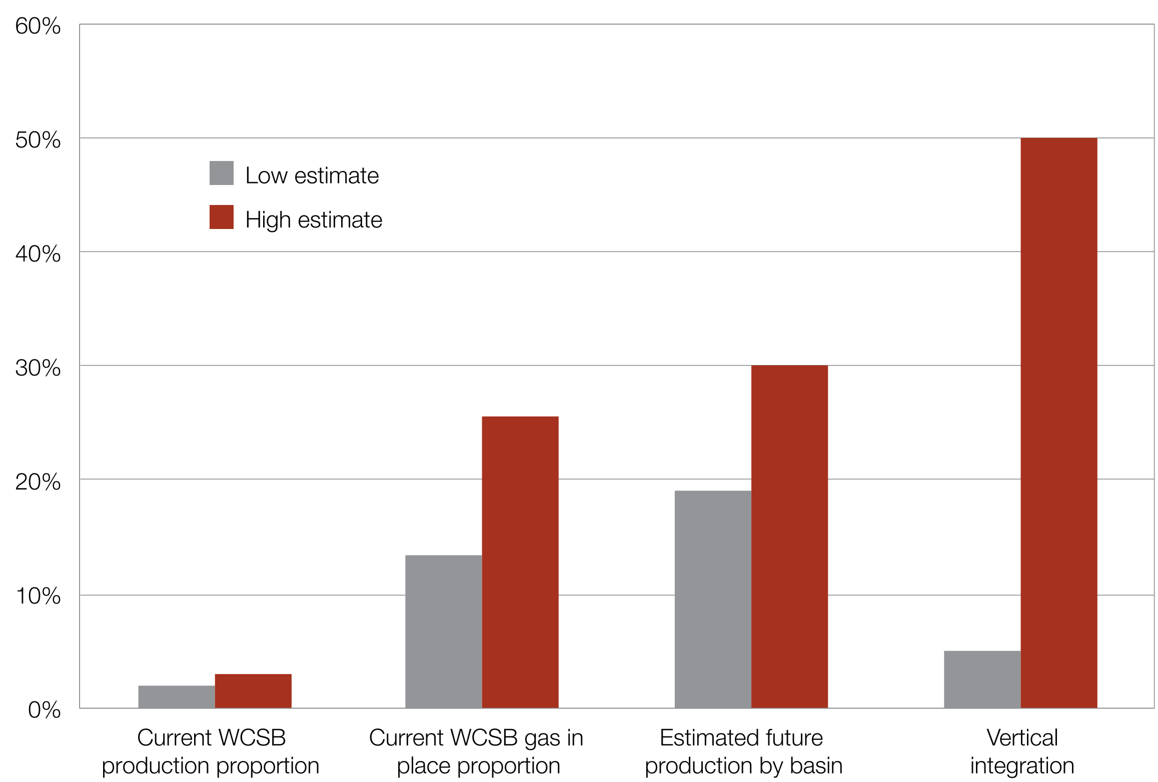
6.7 ESTIMATING THE RANGE OF LNG-INDUCED GAS EXTRACTION FROM FNFN TERRITORY

Given inherent uncertainties in futuring exercises, and the large number of variables involved in particular in the gas sector, one cannot predict with a high degree of certainty what exact proportion of B.C. LNG-induced gas extraction will come from FNFN territory. However, given the extensive secondary data examined in Section 6, a defensible, realistic range of potential values can be established.

Figure 8 identifies four sets of low and high proportional ranges of FNFN-based supply to B.C. LNG export facilities, based on four of the five main variables considered in Section 6:

- Current proportion of total WCSB production;
- Gas-in-place estimates as a proportion of WCSB totals;
- Published estimates of future FNFN territory gas production rates, as a proportion of estimated total WCSB production rates; and
- Degree of vertical integration into FNFN territory of current LNG export proposals/proponents.

Figure 8: Range of estimates of proportion of B.C. LNG exports from FNFN territory, by variable



The first variable is historic and verifiable. The second and third variables are based on a variety of published quantitative estimates of future activities, and thus are subject to a higher degree of uncertainty. The fourth variable is subject to an even higher degree of uncertainty given its focus on linkages between companies in FNFN territory and the potential future BC LNG export sector. This variable is of high importance but inherently uncertain, given it remains unknown which LNG projects will proceed.

The proportions range from two per cent (low estimates of current FNFN territory proportion of WCSB gas production) to 50 per cent (if LNG projects with strong upstream tenure connections to FNFN territory are the primary LNG export projects that proceed).

Not characterized in the table, but a critical fifth consideration in developing realistic scenarios, were FNFN basins' competitive advantages and disadvantages versus other WCSB gas plays.

Of the five variables considered, the author suggests the most important, in declining order, are:

1. Vertical integration of specific LNG projects into FNFN territory.
2. Competitive advantages of different basins.
3. Estimates of likely future production proportions in the WCSB from FNFN territory.
4. Total resources (given more than abundant reserves in all unconventional WCSB plays, this factor does not appear to be a limiting factor).
5. Current production proportion (not likely strongly indicative of future supply, given #3 above and the relative immaturity of all the unconventional WCSB plays).

6.7.1 Discussion

This report has provided evidence to support the following findings related to the estimation of the proportion of LNG-induced gas extraction likely to come from FNFN territory:

- Currently FNFN territory produces only about 1/6th as much gas as the Montney play in B.C. and only two to three per cent of WCSB totals. There are, however, a variety of reasons to expect the current low proportion of total WCSB gas produced out of FNFN territory is a poor predictor of future trends.
- The Montney shale/tight gas play south of FNFN territory is more advanced and has a variety of competitive benefits over FNFN gas (proximity to market, cheaper costs, higher NGLs, more infrastructure, lower CO_2 content). As a result, Montney will likely be tapped more aggressively than FNFN territory early in any LNG demand scenario.
- There will likely be enough market pressures to see more aggressive growth in Horn River production, and Liard River exploration, development, and production, in any B.C. LNG demand scenario.
- Given the scale of investment in Horn River in recent years and the production-ready nature of the play, as well as vertical ties in FNFN territory for many players eager to get into the LNG market, LNG will spark production growth in FNFN territory.

- Ultimately, much depends on which LNG projects proceed; this is a large remaining unknown.
- Gas deposits in FNFN territory, given its large resource base and vertical integration with several LNG proponents, may well be tapped aggressively through all stages of LNG demand.

Given the above-noted balance of factors, the most realistic range of natural gas to be supplied from FNFN territory as a proportion of total WCSB supply to B.C. LNG exports is between 10 and 25 per cent.

If measured by current proportion of WCSB total production, FNFN gas' proportion is very low at approximately two to three per cent. If measured by marketable estimates using a mixture of government and industry estimates, the proportion of likely future supply that will come from FNFN territory is much higher at between 13 and 25 per cent. Actual estimates of future FNFN proportions of total WCSB gas production are in relative lockstep with this proportion at between 19 and 30 per cent.

However, these relatively high values should be tempered by another not easily quantifiable factor – competitiveness on a basin-by-basin basis. Most analysts agree Montney has many advantages (wet gas which is more valuable, existing infrastructure, huge gas reserves) that means it will be tapped first and more intensively than Horn or Liard for at least the next five to ten years and potentially beyond. The Duvernay play in central and western Alberta is also a recent comer that may also have some competitive advantages long term over FNFN territory gas (though this is yet to be determined). In light of some of the competitive disadvantages of the FNFN basins versus some WCSB competitors, the author suggests a downgrading of likely future production proportion below that estimated in Figure 8 for variables two and three from 13 to 30 per cent,[68] down to 10 to 25 per cent.

Finally, vertical linkages between would-be LNG exporters and holdings in FNFN territory (and other basins) were considered. Here, it is all about which LNG facilities actually open. There are strong ties for some of the LNG export proponents upstream into FNFN territory. This report adopted a range between 5 and 50 per cent to reflect the high degree of influence of this variable on the likely ultimate outcome, but note it is also the variable with the highest uncertainty. As a result, this factor does not revise the estimate that the most realistic range for the proportion of future LNG-induced gas extraction from FNFN territory is 10 to 25 per cent.

Given the above-noted balance of factors, the most realistic range of natural gas to be supplied from FNFN territory as a proportion of total WCSB supply to B.C. LNG exports over the initial 20 year production timeline of 2018 to 2038 is between 10 and 25 per cent.

68 The author here used the low end of "Current WCSB Gas in Place" and the high end of "Estimated Future Production by Basin" estimates.

SECTION 7

Establishing LNG-Induced Gas Extraction Scenarios

7.1 ESTABLISHING A REALISTIC RANGE OF SCENARIOS

Table 11 brings together the two main findings of this report (low and high B.C. LNG exports and the proportion of LNG feedstock sourced from FNFN territory shale basins) to provide a series of potential LNG-induced extraction scenarios for FNFN territory, measured in Bcf/day.

Table 11: FNFN LNG-induced gas extraction matrix

LNG demand (2018–2038 average)/FNFN production proportion	10% FNFN gas	25% FNFN gas
Low scenario: 4.9 Bcf/day	0.49 Bcf/day	1.23 Bcf/day
High scenario: 10.7 Bcf/day	1.07 Bcf/day	2.68 Bcf/day

Notes: This table includes only new gas production required to support the LNG export sector. In contrast, Figure 10 below adds LNG demand on top of current FNFN gas production rates. Note that Figure 10 assumes there will be no growth in these production rates for the domestic and North American markets from current rates.

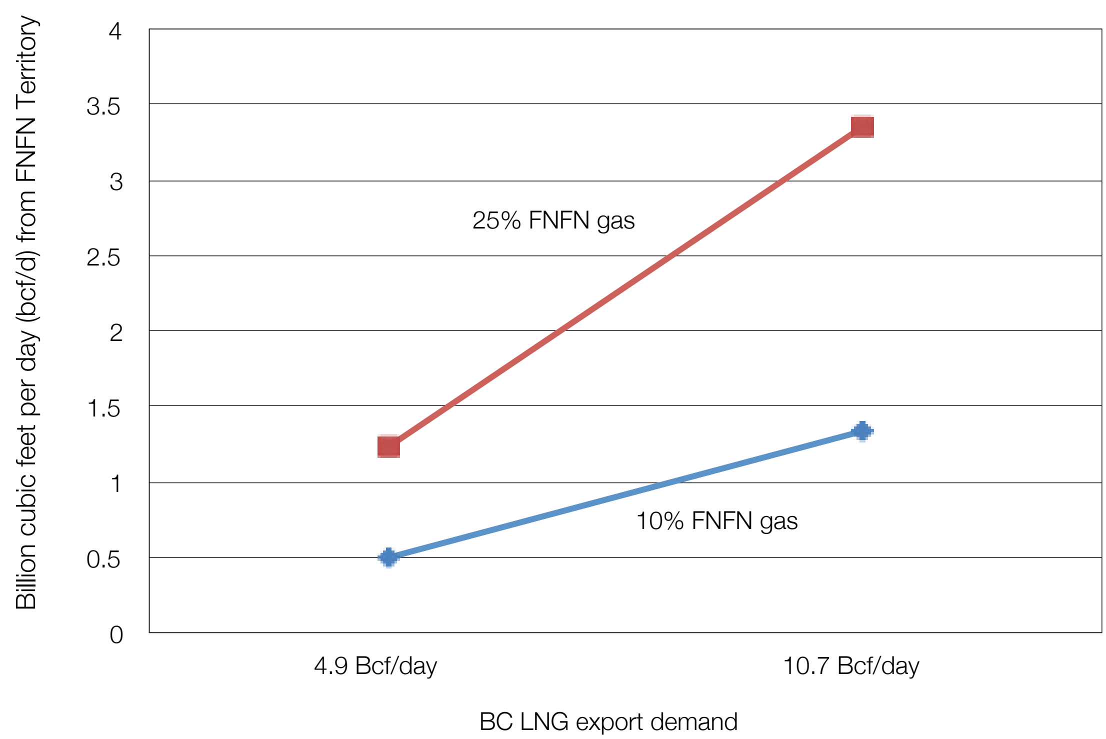
Table 11 and Figure 9 show a continuum of between 490 Mmcf/day and 1.07 Bcf/day of induced gas production in a more conservative estimate of 10 per cent of future WCSB gas supply as LNG feedstock coming from FNFN territory. At a 25 per cent proportion of gas coming from FNFN territory to fuel the B.C. LNG export sector, the continuum ranges from 1.23 Bcf/day to 2.68 Bcf/day.

These numbers equate to between 178 and 978 Bcf/year of natural gas extracted from FNFN territory as a result of the B.C. LNG export sector. When converted to LNG production, the amount equates to between 3.75 and 20.5 million tonnes per annum. This volume ranges from an amount sufficient to support a small portion of a single medium-sized LNG facility to enough gas to support a large LNG facility or two medium-sized LNG facilities.

Over a 20 year period, these average amounts of production per year would equate to between 3.56 Tcf and 19.5 Tcf of LNG-induced additional gas extraction from FNFN territory.

Table 11 and Figure 9 identify that there is a high range of variability in the likely induced demand created for FNFN gas by LNG exports from B.C. A large difference exists between the highest predicted FNFN gas production scenario and the lowest (2.68 Bcf/day vs. 0.49 Bcf/day; see Figure 10). In the author's opinion, this 5.5-fold difference provides a sufficiently broad view of potential natural gas development scenarios moving forward into Phase 2 to capture the majority of potential outcomes.

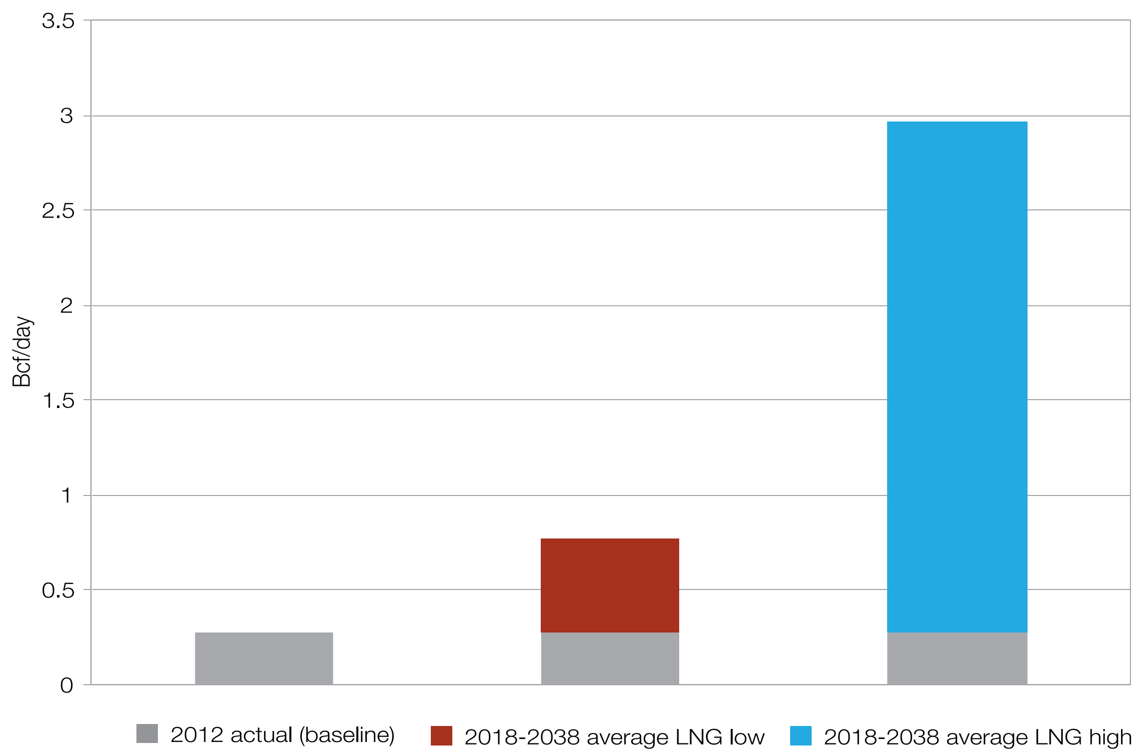
Figure 9: LNG-induced gas extraction scenarios for basins in FNFN territory 2018–2038



Equally important is that most scenarios within this range would see significant increases in the amount of gas produced from FNFN territory over and above historic and current numbers. As illustrated in Figure 10 on the following page, the lowest LNG demand scenario in FNFN territory would be 160 per cent more than 2012 gas production levels from FNFN territory of 281 Mmcf/day. At the high end of the realistic scenario scale, that number jumps to an almost 10-fold difference. Even if FNFN territory's contribution to the North American gas supply sector remained at 2012 levels (a very tenuous assumption), LNG-induced extraction would drive FNFN territory production up to a total of between 770 Mmcf/day to 2.96 Bcf/day.

This report treats as equally possible, each of the LNG-induced FNFN gas extraction outcomes within the range of scenarios described. What is readily apparent is that even with conservative (low end) estimates, the B.C. LNG export sector will induce significant additional development in FNFN territory. Indeed the reality of this is already apparent, with the attractiveness of the LNG export sector being a major driver identified by industry,

Figure 10: Increase in total production from FNFN territory under low and high LNG-induced gas extraction scenarios



government and industry analysts for continuation or resumption of activities within FNFN territory during a North American natural gas supply glut.[69]

This study specifically erred on the side of conservative estimates where possible in this scenario development exercise. Thus, the likely 10 per cent additional required gas for power generation and transportation in the LNG export production system (U.S. EIA 2012) is not included in the calculations. Nor is the additional 10 to 19 per cent of "shrinkage" (product losses in processing) between raw and sales gas (Walden and Walden 2012). In addition, potential "induced exploration effects," wherein new demand for LNG may see expansion of supply by an amount greater than the LNG requirement, are not included in the calculations.[70] Taken together, the conservative assumptions underlying the analysis likely reduce the calculated demand on FNFN territory, as compared to the actual demand. Given this built-in conservatism, it is possible that the actual outcomes in terms of LNG-induced gas extraction from FNFN territory may exceed the high end estimated within this study. In contrast, for the same reasons it is extremely unlikely that the low end estimate herein will exceed the actual outcome.

69 Greg Colman, energy analyst for the National Bank, suggests that drilling activity will need to begin long before LNG export facilities are commissioned, and that *some 200 per cent of export capacity has to be available at the time exports commence* (Schaefer 2013; emphasis added). As a result, even before final investment decisions are made, large amounts of exploration and well completion is expected.

70 Priddle (2013a), following work completed by Ziff Energy Group for WCC Ltd.'s NEB export licence application, identifies a potential replacement ratio approaching 1.4 times the required gas feedstock for an LNG facility, meaning that the induced demand from LNG is likely to cause increased gas development and extraction over and above that required to feed the LNG facilities.

As mentioned in Section 6.6 above, much depends on which LNG facilities are built. For example, should even two vertically integrated LNG facilities with strong ties to FNFN territory proceed, this study's high end estimate of 2.68 Bcf/day would likely be exceeded. Priddle (2013b) previously identified that the average required exports for each of four of the proposed LNG projects (LNG Canada, Pacific Northwest, Prince Rupert, and WCC) is equivalent to 3.35 Bcf/day.[71] This study's high estimate of LNG-induced production in FNFN territory is well below the export feedstock needed for any one of these four projects alone. This speaks to the conservative nature of the high-end induced extraction estimate.

7.1.1 Factors Potentially Influencing Outcomes

Table 12 identifies a series of factors that, independently, may cause the actual LNG-induced gas extracted from FNFN territory over the 2018–2038 period to grow or shrink within the range of realistic scenarios described above. In reality, each factor will interact with others in a difficult to predict combination.

Table 12: Factors potentially influencing actual LNG-induced gas extraction levels from FNFN territory

Factor	LNG-induced gas extraction from FNFN Territory likely to grow if…	LNG-Induced gas extraction from FNFN Territory likely to decline if…
Contribution of northern part of Montney Basin in FNFN territory to gas production rates (unknown)	Gas production from northern portion of Montney in FNFN territory is strong	Gas production from northern portion of Montney in FNFN territory is weak (*NOTE: this may not reduce production in FNFN territory, but will not increase it*)
GHGs/Carbon Tax	Carbon tax not enforced for gas plants	A carbon tax is applied on direct emissions of CO_2 from gas plants
Asian Gas Prices	Asian gas price premium over North American markets is maintained	Asian gas prices drop (see See *Price Differentials in North American and Asian Natural Gas Markets* on page 23)
North American Gas Prices	North American gas prices stay low in comparison to Asian prices	North American gas prices increase to a point where liquefaction for export is less attractive than domestic market sales[a]
EUR per well	EUR numbers from Liard and Horn River remain well above industry average	EUR in FNFN territory declines to close to industry average
Pipeline Capacity	Planned northern pipelines like Komie North and North Montney Mainline proceed	Pipeline capacity from FNFN territory is not increased, and gas is "stranded' in FNFN territory

Note: [a] While this would reduce the LNG-export induced extraction levels, it could result in higher overall extraction levels to supply North American markets.

71 The proposed total capacity of these four projects is 93.6 mtpa, or an average of 23.4 mtpa. Using this report's more conservative conversion estimates (which ignore process losses and power requirements), this equates to 3.04 Bcf/day of feedstock.

SECTION 8

Phase 1 Summary and Next Steps

8.1 SUMMARY OF PHASE 1 FINDINGS

Although there remains uncertainty as to exactly how LNG-induced WCSB natural gas extraction will affect production levels on a basin-by-basin level, using a variety of industry, government and other published sources, this report has developed the following defensible range of scenarios:

1. Annual B.C. LNG exports will most likely be between 37.5 and 82 mtpa, starting about 2018, and lasting over an initial 20 year period (the lifetime of the B.C. LNG sector, while not estimated herein, is likely to be more than 50 years).
2. 10 to 25 per cent of the gas for B.C. LNG export facilities will come from FNFN territory.
3. As a result of #1 and #2, development of a B.C. LNG export sector will induce between 490 Mmcf/day and 2.68 Bcf/day in gas extraction from shale gas basins in FNFN territory.

The scenarios developed indicate that the creation of an LNG export sector will stimulate/induce significant growth in gas extraction from FNFN territory. In 2012, gas extraction within FNFN territory averaged 0.28 Bcf/day. As a result of LNG export sector requirements, gas extraction from FNFN territory can be expected to increase by somewhere between 160 per cent and ten-fold.

In 2012, gas extraction within FNFN territory averaged 0.28 Bcf/day. As a result of LNG export sector requirements, gas extraction from FNFN territory can be expected to increase by somewhere between 160 per cent and ten-fold.

8.2 RECOMMENDATIONS FOR FURTHER WORK

This study, like the fledgling B.C. LNG export sector itself, is preliminary and exploratory in nature. More study of LNG export and gas production issues is required. Conduct of additional, public, scenario analyses to refine those identified in this preliminary study is part of this required further work. It is critical for industry and government to build proper scenario analysis into planning initiatives and environmental assessments associated with the fledgling B.C. LNG production system, as recommended by Duinker and Greig (2007) and Greig and Duinker (2007).

This study, like the fledgling B.C. LNG export sector itself, is preliminary and exploratory in nature. More study of LNG export and gas production issues is required.

In addition, effects modeling and a much stronger emphasis on strategic cumulative effects assessment, based in part on such scenarios of a range of future reasonably foreseeable outcomes, is a critical tool for future planning. For such work to have meaning, it must occur prior to important decisions being made. Phase 2 of this study is an initial attempt to identify some of the upstream implications of these LNG scenarios that are likely to fuel change in FNFN territory.

8.3 INTRODUCTION TO PHASE 2 – EFFECTS MODELING

> *…in recent months…the [B.C. Oil and Gas] Commission has seen an increase in applications and authorizations to drill wells compared with 2012, with much of the activity pinned to B.C.'s LNG potential… it doesn't make sense to drill new wells with current low gas prices. It is more likely LNG proponents are drilling to prove that they have the necessary reserves to support their projects.* – Penner (2013), July 31, 2013

The effects of LNG-induced demand are already being felt in FNFN territory, as evident from increasing drilling applications and advancement of plans to use more and bigger rigs to expand resources in the Liard, Horn River and Cordova Embayment shale gas basins. According to the Petroleum Services Association of Canada, in 2013 drilling in B.C. was expected to rise by 11 per cent. Investment bank Peters & Co. concurred, suggesting:

> *…annualized rig demand for these plays has the potential to increase to upwards of 300 rigs, with this predicated on the Montney and Horn River being principal supply sources for Canadian LNG export.*[72]

72 Both sources cited in www2.canada.com/calgaryherald/iphone/news/latest/story.html?id=8707463

There is strong incentive both for companies seeking vertical integration in the LNG production system and for non-LNG players who have seen their gas "stranded" in the WCSB the past couple years due to low prices and stiff U.S. shale competition, to increase exploration and development of gas supply capacity in advance of the "LNG revolution" in B.C. Gas reserves need to be proven up both for vertically integrated companies seeking Asian off-take purchase agreements for their LNG projects, and non-LNG gas producers seeking market share for their product. These incentives are already causing growth in exploration and development in FNFN territory, in advance of final investment decisions on any of the proposed LNG export facilities. Drilling work in Liard, in particular, has already shown signs of growth in 2013 (Penner 2013). *Change is coming.*

Redden (2012) suggests one of the primary reasons the provincial government repeated its $120 million royalty credit program to the natural gas sector in February 2012 was "to stimulate infrastructure expansion and ensure that the Kitimat LNG terminal remains well-fed." Redden identified the Horn River and Montney basins as the two primary basins which will be expanded to ensure this security of supply. Redden's statement suggests that as of 2012, infrastructure in these two plays (meaning primarily exploration and production of natural gas) was inadequate to fuel the Kitimat LNG terminal itself over the long term. The Kitimat LNG facility is merely the tip of the B.C. LNG iceberg, a mere 1/14th of the proposed LNG export capacity proposed to date. This means that a great deal more exploration activity will need to occur to firm up gas supplies from the growing unconventional gas supplies of the WCSB, in places like Montney, Liard, Horn River, Cordova Embayment, and Duvernay.

Armed with realistic scenarios of how much growth in gas extraction from FNFN territory would be caused by development of a B.C. LNG sector, Phase 2 of this study focuses on estimating how LNG-induced demand, the advance effects of which are already being felt, will change FNFN lands and add to existing cumulative effects within FNFN territory.

Armed with realistic scenarios of how much growth in gas extraction from FNFN territory would be caused by development of a B.C. LNG sector, Phase 2 of this study focuses on estimating how LNG-induced demand, the advance effects of which are already being felt, will change FNFN lands and add to existing cumulative effects within FNFN territory. Within this range of induced gas development scenarios, environmental and social, economic and cultural implications for FNFN, alone and in combination with existing gas development effects on the community, can be modeled using experiential knowledge and data from FNFN Lands Department and proxy studies of impacts of shale gas per unit of production from other jurisdictions as triangulation sources, among other tools. This work includes development of estimates of likely infrastructure requirements to fuel LNG-induced gas extraction from FNFN territory, and estimating linear and areal disturbance levels that would likely result on the ground in FNFN territory, among other considerations (e.g., effects on water use, GHG emissions).

The Phase 2 Report for this study includes additional recommendations related to studying, avoiding or minimizing the effects of this LNG-induced gas extraction on FNFN territory.

REFERENCES

Adams, C. (2013). Summary of Shale Gas Activity in Northeast British Columbia 2012. Oil and Gas Reports 2013-1, B.C. Ministry of Natural Gas Development: Geoscience and Strategic Initiatives Branch. Accessed at www.empr.gov.bc.ca/Mining/Geoscience/PublicationsCatalogue/OilGas/OGReports/Documents/2012/Summary%20of%20Shale%20Gas%20Activity%20in%20NEBC%202011%20Version%20HQ.pdf

Advanced Resources International Inc. (2013). EIA/ARI World Shale Gas and Shale Oil Resources Assessment. May 17, 2013. Accessed at www.adv-res.com/pdf/A_EIA_ARI_2013%20World%20Shale%20Gas%20and%20Shale%20Oil%20Resource%20Assessment.pdf

Anderson, Z. (2010). North American Natural Gas. Presented for BP plc at the Energy Futures Conference 2010. Accessed at www.neb-one.gc.ca/clf-nsi/rnrgynfmtn/nrgyrprt/nrgyftr/cnslttnrnd4/prsnttn/zoe_anderson.pdf

Antunes, P., Coad, L., Macdonald, A. (2012). The Role of Natural Gas in Powering Canada's Economy. The Conference Board of Canada: Energy, Environment, and Transportation Policy. Accessed at www.conferenceboard.ca/e-library/abstract.aspx?did=5251

Apache Corp. (2013). 2013 Annual Shareholder Meeting. May 16, 2013.

Apache Corp. (2012). "Liard Discovery Truly a World-Class Play." Explore Newsletter, November 2012, December 6, 2012. Accessed at www.apachecorp.com/News/Articles/View_Article.aspx?Articl.ItemID=2877.

Aurora Liquefied Natural Gas Ltd. (2013). Application for Licence to Export Liquefied Natural Gas. Application to the National Energy Board, November 29, 2013.

B.C. Hydro (2013). 2013 Integrated Resource Plan. August 2013. Accessed at www.bchydro.com/energy-in-bc/meeting_demand_growth/irp/document_centre/reports/august-2013-irp.html

B.C. Ministry of Energy and Mines (2013). Liquefied Natural Gas: A Strategy for B.C.'s Newest Industry: One year update. Victoria: B.C. Ministry of Energy and Mines. Accessed at www.gov.bc.ca/com/attachments/LNGreport_update2013_web130207.pdf

B.C. Ministry of Energy and Mines (no date). British Columbia's Natural Gas Strategy: Fuelling B.C.'s Economy for the Next Decade and Beyond. Accessed at www.gov.bc.ca/ener/popt/down/natural_gas_strategy.pdf

B.C. MEM and NEB (2011). Ultimate Potential for Unconventional Natural Gas in Northeastern British Columbia's Horn River Basin. Oil and Gas Reports 2011-1. B.C. Ministry of Energy and Mines and the National Energy Board. Accessed at www.neb-one.gc.ca/clf-nsi/rnrgynfmtn/nrgyrprt/ntrlgs/hrnrvr/hrnrvrm-eng.html

B.C. OGC (2013a). Hydrocarbon and By-Product Reserves in British Columbia: 2012. Victoria: B.C. Oil and Gas Commission.

B.C. OGC (2013b). Oil and Gas Land Use in the Fort Nelson LRMP Area of British Columbia. March 2013. B.C. Oil and Gas Commission. Accessed at www.bcogc.ca/node/8233/download

B.C. OGC (2010). Horn River Basin Status Report for 2009/2010. Victoria: B.C. Oil and Gas Commission.

Bentek Energy (2013). LNG Exports: The Global Thirst for North American Shale Gas. Accessed at www.bentekenergy.com/LNGexports.aspx.

BMO (2012). A & D Drill Bits: March 2012. BMO Capital Markets, March 6, 2012. Accessed at https://datarooms.ca.bmo.com/Login%20Page%20Document%20Library/ADLibrary/ADDrillBits/AD%20Drill%20Bits%20Duvernay%20March2012.pdf

BMO (2011). A & D Drill Bits: October 2011. BMO Capital Markets. Accessed at https://datarooms.ca.bmo.com/Login%20Page%20Document%20Library/ADLibrary/ADDrillBits/AD%20Drill%20Bits%20Montney%20Oct%2018%202011.pdf

CAPP (2012). Canadian Oil and Gas Industry Outlook – Opportunities and Challenges. Presentation by Canadian Association of Petroleum Producers President Dave Collyer at CORE Energy Conference – Halifax, October 3, 2012.

CAPP (2010). Climate Policy and Energy Policy – Where Do They Meet? Presentation by Canadian Association of Petroleum Producers President Dave Collyer to BCBC and B.C. Chamber of Commerce, B.C. Energy Conference, October 27, 2010.

CBC News (2013). The LNG Boom? April 29, 2013. Accessed at www.cbc.ca/news/canada/british-columbia/the-lng-boom-1.1364023

Centre for Energy (2013). British Columbia – Statistics. Accessed at www.centreforenergy.com/FactsStats/statistics.asp?template=5,1

Crist, V. (2013). "All gassed up." Haisa Laas – Newsletter of the Council of the Haida Nation. September 2013, 10-13.

Daly, J. (2013). "Canada's Montney Natural Gas Basin – Game Changer?" OilPrice.com, November 14, 2013. Accessed at http://oilprice.com/Energy/Natural-Gas/Canadas-Montney-Natural-Gas-Basin-Game-Changer.html

Duinker, P. and L. Greig (2007). Scenario analysis in environmental impact assessment: Improving explorations of the future. Environmental Impact Assessment Review, 27, 206-219.

Entrekin, S., Evans-White, M., Johnson, B. and E. Hagenbuch (2011). Rapid expansion of natural gas development poses a threat to surface waters. Frontiers in Ecology and the Environment, 9(9), 503-511.

Environmental Law Centre (2013). Request that Minister Polak Order a Strategic Economic and Environmental Assessment of Liquid Natural Gas (LNG) Development in British Columbia. Environmental Law Centre, University of Victoria, on behalf of Northwest Institute for Bioregional Research, August 1, 2013. Accessed ad http://northwestinstitute.ca/images/uploads/ELC-2013Aug1-Aglukkaq-Polak-Request.pdf

Ernst & Young (2013a). Global LNG: Will new demand and new supply mean new pricing? Accessed at www.ey.com/Publication/vwLUAssets/Global_LNG_New_pricing_ahead/$FILE/Global_LNG_New_pricing_ahead_DW0240.pdf

Ernst & Young (2013b). Potential Revenues to BC Government from Potential Liquefied Natural Gas Development in BC. Prepared for the Ministry of Energy, Mines & Natural Gas. Accessed at www.llbccat.leg.bc.ca/ipac20/ipac.jsp?index=BIB&term=528493

Fraser Institute (2012). Laying the Groundwork for BC LNG Exports to Asia. Study Authored by Angevine, G. and V. Oviedo, October 2012. Accessed at www.fraserinstitute.org/uploadedFiles/fraser-ca/Content/research-news/research/publications/laying-the-groundwork-for-BC-LNG-exports-to-asia.pdf

Fross, D. and S. Lyle. (2013). Guidelines for Voluntary Baseline Groundwater Quality Sampling in the Vicinity of Hydraulic Fracturing Operations. Kansas Geological Survey, Public Information Circular, 34, April 19, 2013 . Accessed at www.kgs.ku.edu/Publications/PIC/pic34.html

Government of Canada (2013). Responsible Shale Development: Enhancing the knowledge base on shale oil and gas in Canada. Energy and Mines Ministers' Conference, Yellowknife, NWT, August 2013. Accessed at www.nrcan.gc.ca/sites/www.nrcan.gc.ca/files/pdf/publications/emmc/Shale_Resources_e.pdf

Grant Thornton (2013a). Employment Impact Review: February 2013. Prepared for the Ministry of Energy, Mines and Natural Gas. Accessed at www.newsroom.gov.bc.ca/downloads/Grant_Thornton_LNG_Employment_Impacts.pdf

Grant Thornton (2013b). Potential LNG Revenue to the BC Government. Prepared by Grant Thornton LLP for the Ministry of Energy, Mines, and Natural Gas. www.llbc.leg.bc.ca/public/pubdocs/bcdocs2013/528495/grant%20thornton%20-%20lng%20revenue.pdf

Gregory, Kelvin B., Vidic, Radisav D., and Dzombak, David A. (2011, June). "Water Management Challenges Associated with the Production of Shale Gas by Hydraulic Fracturing." Elements 7(3): 181-186.

Greig, L. and P. Duinker (2007). Scenarios of Future Developments in Cumulative Effects Assessment: Approaches for the Mackenzie Gas Project. Prepared for the Mackenzie Gas Project – Joint Review Panel, March 12, 2007. Accessed at www.ceaa-acee.gc.ca/155701CE-docs/ESSA_Technologies-eng.pdf

Hamilton, G. (2012). "Liard Basin find best reservoir on continent, stakeholder says." Vancouver Sun, June 15, 2012. Accessed at www.canada.com/vancouversun/news/business/story.html?id=61a76f2d-048a-4fa6-ba89-02b51aea87e0

Heffernan, K. and Dawson, F. (2010). An Overview of Canada's Natural Gas Resources. Canadian Society of Unconventional Resources, May 2010. Accessed at www.csur.com/sites/default/files/Canada's_Resource_Base_Overview.pdf

Howarth, R., Santoro, R. and A. Ingraffea (2011). "Methane and the greenhouse-gas footprint of natural gas from shale formations." Climatic Change, 106, 679-690.

Hughes, D. (2014). BC LNG: A Reality Check. Global Sustainability Research Inc., January 17, 2014.

Hussain, Y. (2012). "What's driving demand in the Duvernay." Financial Post, December 21, 2012. http://business.financialpost.com/2012/12/21/whats-driving-demand-in-the-duvernay/?__lsa=1869-1310

International Energy Agency (2013). IEA – Gas. Accessed at www.iea.org/aboutus/faqs/gas/

International Energy Agency (2012). World Energy Outlook 2012 Factsheet. How Will Global Energy Markets Evolve to 2035? Accessed at www.worldenergyoutlook.org/media/weowebsite/2012/factsheets.pdf

International Gas Union (2013). World LNG Report – 2013 Edition. Accessed at www.igu.org/gas-knowhow/publications/igu-publications/IGU%20World%20LNG%20Report%202013.pdf

International Gas Union (2011). World LNG Report 2011. Accessed at www.igu.org/gas-knowhow/publications/igu-publications/LNG%20Report%202011.pdf

Jensen, J. (2011). Asian Natural Gas Markets Supply Infrastructure, and Pricing Issues. February 2011. Accessed at www.nbr.org/downloads/pdfs/eta/PES_2011_Jensen.pdf

Johnson, E. (2012). "Water issues associated with hydraulic fracturing in northeast British Columbia," Presentation at 6th B.C. Unconventional Gas Technical Forum, April 3, 2012, Victoria, B.C.

Johnson, E. (2009). "Water Potential of the Mississipian Debolt Formation in the Horn River Basin, Northeastern British Columbia." Geoscience Reports 2009, Ministry of Energy, Mines and Petroleum Resources, 39 – 47.

Jordan Cove LNG L.P. (2013). Application For a License Pursuant to section 117 of the National Energy Board Act Authorizing the Export of Gas. September 9, 2013.

King, George E. (2013). Fracture Fluid Additive and Formation Degradations. EPA Workshop on Hydraulic Fracturing, Workshop No. 1, Chemicals. Accessed at www2.epa.gov/sites/production/files/documents/fracturefluidadditivesandformationdegradations.pdf

Kitimat LNG (2013). Natural Gas Supply. Kitimat LNG Facility. Accessed at www.kitimatlngfacility.com/Supply/natural_gas_supply.aspx

KM LNG (2010). Kitimat LNG NEB Export License Application. Appendix 3a – Apache Corporate Supply Pool. December 9, 2010. KM LNG Operating General Partnership

Lewis, J. (2013). "Gas marketers see opportunity in Western Canada LNG exports to Asia." Calgary, Alberta: National Post: Financial Post. Accessed at http://business.financialpost.com/2013/08/15/gas-marketers-see-opportunity-in-western-canada-lng-exports-to-asia/?__lsa=08fe-a4a8

Lewis, J. (2012). "Pieridae Energy proposes $5 billion East Coast LNG facility." Alberta Oil Magazine. Accessed at www.albertaoilmagazine.com/2012/10/pieridae-energy-proposes-east-coast-lng-facility/

Linley, D. 2011. Fracking under Pressure: The Environmental and Social Impacts and Risks of Shale Gas Development. Amsterdam: Sustainalytics. Accessed at www.sustainalytics.com/sites/default/files/unconventional-fossil-fuel-shalegas_final.pdf

LNG Canada Development Inc. (2012). Application [to the National Energy Board for an Export Licence]. July 27, 2012. Accessed at https://docs.neb-one.gc.ca/ll-eng/llisapi.dll?func=ll&objId=834279&objAction=browse&viewType=1

Macquarie Research. (2012a). Canadian LNG: The race to the coast. Prepared by Macquarie Capital Markets Canada. Accessed at www.investorvillage.com/uploads/8056/files/Cdn_LNG_100912.pdf

Macquarie Research (2012b). Australian LNG Outlook. Prepared by Macquarie Securities (Australia) Limited, September 10, 2012.

Mason, J. (2011). "Well production profiles for the Fayetteville shale gas play." Pre-publication article, Oil and Gas Journal, April 4, 2011 Issue.

Mirski, P. and L. Coad (2013). Managing Expectations: Assessing the Potential of B.C.'s Liquid Natural Gas Industry. Calgary, AB: Canada West Foundation. Accessed at http://cwf.ca/pdf-docs/publications/ManagingExpectations_October2013-2.pdf

Moniz, E. (chair), Jacoby, H. (co-chair), and A. Meggs (co-chair) (2011). The Future of Natural Gas: An Interdisciplinary Study. Cambridge, Massachusetts: MIT Press. pp. 25. Accessed at http://mitei.mit.edu/system/files/NaturalGas_Report.pdf

National Bank (2013). "Quantifying the LNG Impact: Potential for Up to $11 Bln (30%) Lift to Annual E&P Spending over the Next Decade." National Bank Financial Daily Bulletin, July 9, 2013.

NEB (2013a). Short-term Canadian Natural Gas Deliverability 2013-2015 – Energy Market Assessment. Calgary: National Energy Board. Accessed at www.neb-one.gc.ca/clf-nsi/rnrgynfmtn/nrgyrprt/ntrlgs/ntrlgsdlvrblty20132015/ntrlgsdlvrblty20132015-eng.html

NEB, National Energy Board of Canada. (2013b). Canada's Energy Future 2013 – Energy Supply and Demand Projections to 2035 – An Energy Market Assessment. Calgary: National Energy Board. Accessed at www.neb-one.gc.ca/clf-nsi/rnrgynfmtn/nrgyrprt/nrgyftr/2013/nrgftr2013-eng.html

NEB (2013c). NEB Approves Four LNG Licence Applications. News Release, December 16, 2013. Calgary: National Energy Board. Accessed at www.neb-one.gc.ca/clf-nsi/rthnb/nws/nwsrls/2013/nwsrls35-eng.html

NEB (2011). Canada's Energy Future: Energy Supply and Demand Projections to 2035 – Energy Market Assessment, 2011. Calgary: National Energy Board. Accessed at www.neb-one.gc.ca/clf-nsi/rnrgynfmtn/nrgyrprt/nrgyftr/2011/nrgsppldmndprjctn2035-eng.pdf

NEB (2010). Natural Gas Supply Costs in Western Canada in 2009 – Energy Briefing Note. Calgary: National Energy Board. Accessed at https://www.neb-one.gc.ca/clf-nsi/rnrgynfmtn/nrgyrprt/ntrlgs/ntrlgsspplcstwstrncnd2009_2010/ntrlgsspplcstwstrncndnrgybrf2009-eng.html

NEB (2009). A Primer for Understanding Canadian Shale Gas – Energy Briefing Note. November 2009. Calgary: National Energy Board. Accessed at www.neb-one.gc.ca/clf-nsi/rnrgynfmtn/nrgyrprt/ntrlgs/prmrndrstndngshlgs2009/prmrndrstndngshlgs2009-eng.html

NEB, B.C. OGC, Alberta Energy Regulator and BC Ministry of Natural Gas Development (2013). Energy Briefing Note: The Ultimate Potential for Unconventional Petroleum from the Montney Formation of British Columbia and Alberta. November 2013. National Energy Board, BC Oil and Gas Commission, Alberta Energy Regulator and BC Ministry of Natural Gas Development Accessed at www.neb-one.gc.ca/clf-nsi/rnrgynfmtn/nrgyrprt/ntrlgs/ltmtptntlmntnyfrmtn2013/ltmtptntlmntnyfrmtn2013-eng.html

Nexen (2013). Aurora LNG. Accessed at www.nexencnoocltd.com/en/Operations/ShaleGas/AuroraLNG.aspx

Northwest Gas Association (2013). 2013 Gas Outlook: Natural Gas Supply, Demand, Capacity and Prices in the Pacific Northwest: Projections through October 2022. Accessed at www.nwga.org/wp-content/uploads/2013/04/2013NWGAOutlookWEB.pdf

Nova Gas Transmission Ltd (2011). Northwest Mainline Expansion Application. Section 2: Supply and Markets. Application to the National Energy Board. Accessed at https://docs.neb-one.gc.ca/ll-eng/llisapi.dll?func=ll&objId=684358&objAction=browse

Oil and Gas Financial Journal (2013). "Canadian shale update." Oil and Gas Financial Journal, July 11, 2013. Accessed at www.ogfj.com/articles/print/volume-10/issue-7/features/canadian-shale-update.html

Oil and Gas Financial Journal (2012). "Canadian shale holds great promise." Oil and Gas Financial Journal, October 1, 2012. Accessed at www.ogfj.com/articles/print/volume-9/issue-10/features/canadian-shale-holds-great-promise.html

Oil and Gas Journal (2011). "Canada sees 78 tcf marketable in Horn River basin." Oil and Gas Journal, 109(15), August 1, 2011, 56-58.

OnPoint Consulting Inc. (2010). Natural Gas: Fueling British Columbia's Growth. Prepared for the Business Council of British Columbia. Accessed at www.bcbc.com/content/584/2020_201005_Molinski_NaturalGas.pdf

Park, G. (2013). "Two LNG permits sought: Idemitsu, AltaGas apply to National Energy Board; 3 licenses granted." Petroleum News. Accessed at www.petroleumnews.com/pntruncate/557822961.shtml

Pembina Institute (2013). BC LNG Proposals and GHG Emissions. Accessed at http://northwestinstitute.ca/images/uploads/Pembina-LNG-GHG-July2013.pdf

Penner, D. (2013). “Huge natural gas drilling rig destined for B.C. could be Canada’s biggest.” Vancouver Sun, July 31, 2013. Accessed at www.vancouversun.com/business/Huge+natural+drilling+destined+could+Canada+biggest/8733393/story.html

Petroleum Human Resources Council of Canada (2013). B.C. Natural Gas Workforce Strategy and Action Plan. Produced fro the B.C. Natural Gas Workforce Strategy Committee, July 2013.

Petroleum News (2013). “B.C. raises doubts on LNG Goals; Ziff: 5 Plants by 2021 Unrealistic.” Petroleum News, 18 (31), August 4, 2013. Accessed at www.petroleumnews.com/pntruncate/334001884.shtml

Petzet, A. (2008). “BC’s Muskwa Shale shaping up as Barnett gas equivalent,” Oil and Gas Journal, 106, no. 12 (March 24, 2008), 40-41.

PFC Energy (2012). LNG Markets Study. June 2012. Study conducted for the LNG Canada Project. Accessed at www.arcticgas.gov/sites/default/files/documents/lng-canada-12-6-pfc-energy-study-global-lng-mkt.pdf

Poten & Partners (2010). 2015-2035 LNG Market Assessmetn Outlook for the Kitimat LNG Terminal. Prepared for KM LNG Operating General Partnership, October 2010. New York: Poten & Partners.

Priddle, R. (2013a). Export Impact Assessment Report: In respect of an application to the National Energy Board by WCC LNG LTD. For a licence authorizing the export of liquefied natural gas. Prepared for WCC LNG LTD.

Priddle, R. (2013b). Application for a Gas Export License of the National Energy Board: Observations on Export Impact and Surplus Evaluation Pursuant to the National Energy Board Act s. 118. Completed for Woodfibre LNG Export Pte. Ltd. July 23, 2013.

Redden, J. (2012). Horn River: Kitimat LNG Terminal Entices Gas Producers. World Oil, April 2012, 64-76.

(S&T^2) Consultants Inc. (2010). The Addition of Unconventional Natural Gas Supply to GHGenius. Prepared for Natural Resources Canada, March 31, 2010.

Schaefer, K. (2013). Canadian LNG: The 3 Stages of Profits (the 1st is Happening Now). The Resource Investor, August, 2013. Accessed at www.theresourceinvestorcom/RI-archive/2013/0813-schaefer.html

Steve Davis & Associates Consulting Ltd. (2011). Additional Industrial Electricity Load Growth in B.C. to 2025. Prepared for the Canadian Wind Energy Association. Accessed at www.canwea.ca/windvision_bc_e.php

Suttles, D. (2013). Corporate Presentation June 2013. Encana. Accessed at www.encana.com/pdf/investors/presentations-events/corporate-presentation.pdf

Tait, C. (2013). “Encana cuts deep in massive shakeup.” The Globe and Mail, November 5, 2013. Accessed at www.theglobeandmail.com/report-on-business/industry-news/energy-and-resources/encana-to-slash-jobs-spin-off-properties-in-sweeping-overhaul/article15261101/

Thomas, S. (2013). “Aurora LNG files for export license for Grassy Point terminal.” Northern View, November 29, 2013. Accessed at www.thenorthernview.com/news/233877161.html

Thomson Reuters (2013). U.S. Gas via Panama Frightens LNG Exporters Worldwide. Reuters, September 5, 2013. Accessed at www.reuters.com/article/2013/09/05/energy-lng-world-idUSL6N0GV37820130905

TCPL (2013). North Montney Mainline (Aitken Creek and Kahta Sections). Calgary: TransCanada PipeLines Ltd.

Triton LNG Limited Partnership (2013). Application of Triton LNG Limited Partnership. Application to the National Energy Board for an export license, October 29, 2013.

UPI (2013). "Canada at competitive disadvantage for LNG export?" United Press International (upi.com), Business News, August 23, 2013. Accessed at www.upi.com/Business_News/Energy-Resources/2013/08/23/Canada-at-competitive-disadvantage-for-LNG-export/UPI-24401377285594/

U.S. EIA (2013). Technically Recoverable Shale Oil and Shale Gas Resources: An Assessment of 137 Shale Formations in 41 Countries Outside the United States. U.S. Department of Energy, Washington D.C, Energy Information Administration. Accessed at www.eia.gov/analysis/studies/worldshalegas/pdf/fullreport.pdf

U.S. EIA (2012). Effect of Increased Natural Gas Exports on Domestic Energy Markets. January 2012. Washington, D.C.: U.S. Energy Information Administration.

U.S. EIA (2011). Global Natural Gas Prices Vary Considerably. U.S. Energy Information Administration. Accessed at www.eia.gov/todayinenergy/detail.cfm?id=331

Vanderklippe, N. (2012). "Kitimat LNG closer to reality as Chevron to buy out Encana, EOG." The Globe and Mail, December 24, 2012. Accessed at www.theglobeandmail.com/report-on-business/industry-news/energy-and-resources/kitimat-lng-closer-to-reality-as-chevron-to-buy-out-encana-eog/article6699799/

Walden, Z. (2013). Global LNG: Now, Never, or Later? Canadian Energy Research Institute. Accessed at www.ceri.ca/images/stories/2013-02-04_CERI_Study_131_-_Global_LNG.pdf

WCC LNG Ltd. (2013). Application for License to Export Liquefied Natural Gas. Application to National Energy Board, June 2013. Accessed at https://www.neb-one.gc.ca/ll-eng/livelink.exe/fetch/2000/90466/94153/552726/963926/977286/963718/A3I5K4_-_WCC_LNG_Ltd._Application_for_a_Licence_to_Export_LNG?nodeid=963805&vernum=0

Wood Mackenzie (2011). Douglas Channel Energy Project: LNG & North America Natural Gas Market Assessment (2011 – 2033). Prepared for: LNG Partners, LLC for itself and on behalf of its affiliates BC LNG Export Cooperative LLC And Douglas Channel Energy Partnership, March 2011. Accessed at www.arcticgas.gov/sites/default/files/documents/bc-lng-11-3-wood-mac-lng-mkt-assess.pdf

Yep, E. (2013). Asian LNG Prices Rise Sharply. The Wall Street Journal, November 8, 2013. Accessed at http://blogs.wsj.com/moneybeat/2013/11/08/asian-lng-prices-rise-sharply/

Ziff Energy Group (2013a). Long Term Natural Gas Supply and Demand Forecast to 2050: North America and Canada. Prepared for Triton LNG Limited Partnership. Calgary, AB, October 28, 2013.

Ziff Energy Group (2013b). Natural Gas Supply and Demand Forecast to 2046: North American and Canada. Prepared for Woodfibre LNG Export Pte. Ltd. Calgary, AB, July 22, 2013.

Ziff Energy Group (2013c). Natural Gas Supply and Demand Forecast to 2050: North American and Canada. Prepared for Prince Rupert LNG Exports Limited, June 17, 2013.

Ziff Energy Group (2012). Natural Gas Supply and Demand Forecast to 2045: North America and Canada. Prepared for LNG Canada Development Inc., June 2012. Accessed at https://docs.neb-one.gc.ca/ll-eng/llisapi.dll/fetch/2000/90466/94153/552726/834773/834774/834279/A2V3I4_-_Appendix_D_-_Ziff_Energy_Group_-_Natural_Gas_Supply_and_Demand_Forecast_to_2045.pdf?nodeid=834355&vernum=-2

2026 Kennay-Yah Road
RR1 Mile 295 Alaska Highway
Fort Nelson, B.C. V0C 1R0

T: 250-774-6313
F: 250-774-6317
E: reception.lands@fnnation.ca
www.fortnelsonfirstnation.org

253 – 560 Johnson St., Victoria B.C. V8W 3C6
T: 250.590.9017
E: info@thefirelightgroup.com
www.thefirelightgroup.com