FUELING CHANGE

UPSTREAM IMPLICATIONS OF THE B.C. LNG SECTOR

Phase 2: Effects of LNG-Induced Gas Extraction on FNFN Territory

May 6, 2014

Authored by Alistair MacDonald,
The Firelight Group Research Cooperative

Commissioned by Fort Nelson First Nation

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Purpose of the Study

Extremely large reserves of natural gas are located in shale deposits underlying Fort Nelson First Nation (FNFN) territory in northeastern B.C. In recent years, these resources have been unlocked due to hydraulic fracturing (fracking) and horizontal drilling activities, bringing rapid change to FNFN territory.

Liquefied natural gas (LNG) exports are the next frontier facing FNFN, as a result of rapid increases in proposals for development of a B.C. LNG export sector to Asia. To date, minimal work has been done to evaluate the upstream implications of fueling these proposed pipelines and export facilities with natural gas from northeastern B.C.

Given these information deficits amid ongoing concerns about gas sector effects in its territory, FNFN commissioned Alistair MacDonald of The Firelight Group Research Cooperative to conduct a two-phase study to explore how development of an LNG export sector in B.C. may affect FNFN territory. This study represents the first attempt by any party to look at potential effects on the air, water, and land in FNFN territory of B.C. LNG export scenarios. It does so by estimating the amount of gas extraction 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 shale gas production scenarios.

This study represents the first attempt by any party to look at potential effects on the air, water, and land in FNFN territory of B.C. LNG export scenarios.

Phase 1 Findings

Phase 1 developed a range of realistic scenarios of how much natural gas may be extracted from FNFN territory to feed different B.C. LNG export scenarios, finding that:

1. B.C. LNG exports will be between 37.5 and 82 million tonnes per annum (Mtpa), starting about 2018;
2. 10 to 25 per cent of the gas for B.C. export facilities will come from FNFN territory; and
3. As a result of #1 and #2, the BC LNG export sector will induce between 490 million cubic feet per day (Mmcf/day) and 2.68 billion cubic feet per day (Bcf/day) in gas extraction from shale gas basins in FNFN territory.

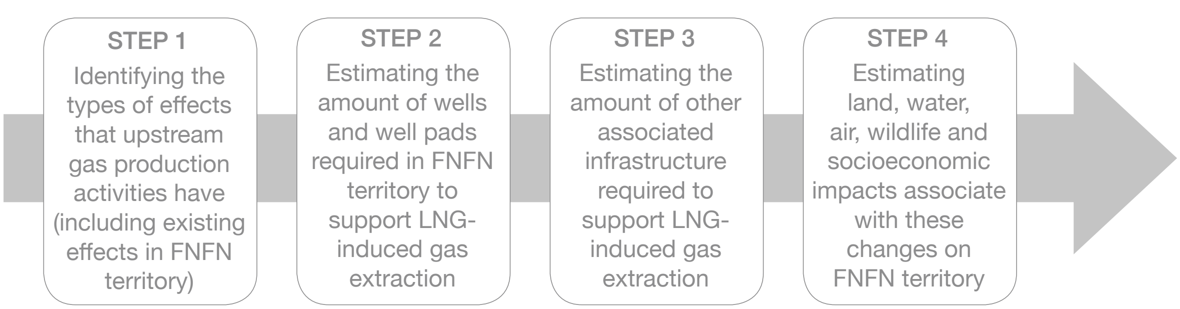
> Phase 1 developed a range of realistic scenarios of how much natural gas may be extracted from FNFN territory to feed different B.C. LNG export scenarios. The overarching finding of Phase 1 is that substantial change is coming to FNFN territory as a result of LNG.

The overarching finding of Phase 1 is that **substantial change is coming to FNFN territory as a result of LNG**.

Phase 2 Methods

Phase 2 of this study focuses on estimating how this new LNG-induced gas extraction will change FNFN lands, waters, and air, among other factors. It does so through the four stage methodology illustrated below:

Steps for Estimating the Physical Impacts of the Gas Production Forecasts from Phase 1



Limitations associated with this study include that emphasis is on impacts within FNFN's three shale gas basins only (the Horn River and Liard Basins and the Cordova Embayment). It is not a cumulative effects assessment; it is a forward looking scenarios projection of incremental activity as a result of the LNG export industry over its first 20 years only.

Step 1: Identifying Upstream Gas Production Activities and Effects

Section 3 of this report uses secondary data (industry data, B.C. Oil and Gas Commission (B.C. OGC) data, academic and other research) to identify:

- Key physical works and activities involved in the upstream (exploration, production and initial transportation toward market) unconventional gas sector;
- Impacts associated with the upstream unconventional gas sector; and
- The gas sector works and activities that have occurred in shale basins in FNFN territory to date, and some of the associated impacts.

The implications of natural gas exploration, development, production and transportation include land clearing, water use, air quality effects, and impacts on wildlife and vegetation, among other factors.

Exploration and development involve the construction of dense networks of seismic lines, roads, well pads and pipelines. These linear and areal disturbances increase habitat fragmentation. New roads and other linear corridors also bring more people into the area. Greater access means greater hunting pressures and potential for higher wildlife mortality from vehicle collisions. Extraction, which occurs through an industrial process known as hydraulic fracturing, involves pumping large volumes of water (the vast majority of which is drawn from nearby rivers, streams and lakes), sand and chemical additives into underground shale formations at high pressures. Gas operations can also cause local air quality problems from gaseous and particulate emissions. They also contribute heavily to B.C.'s greenhouse gas (GHG) emissions footprint, which is linked to climate change.

The implications of natural gas exploration, development, production and transportation include land clearing, water use, air quality effects, and impacts on wildlife and vegetation, among other factors.

FNFN territory has encountered rapid shale gas sector activity growth over the past five to ten years, as described in Section 3.3, which identifies a total impact footprint to date covering over 10 per cent of each of the Horn River Basin and Cordova Embayment. The Liard Basin has not been impacted as extensively yet, but is highly prospective for shale gas and thus likely to be impacted further in an LNG future. Total water withdrawals and contribution to provincial GHG emissions from gas sector activity have also both grown exponentially in FNFN territory over the past decade.

Step 2: Estimating Physical Work and Activity Intensity in FNFN Territory

Section 4 estimates a range of the amount of wells and well pads required in FNFN territory to facilitate LNG-induced gas extraction over the first 20 years of a B.C. LNG export sector. It does so by using several different proxy studies to generate a range of estimates for the number of required wells and pads to produce the gas required from FNFN territory. The outcome is a set of thirteen scenarios of potential future wells and pads required in FNFN territory to support LNG-induced gas requirements between 2018 and 2038.

Step 3: Modeling Physical Works and Activities Required in FNFN Territory to Support LNG-induced Demand

Section 4.3 estimates the average amount of infrastructure required per well or well pad, triangulated from a couple of key inputs:

- Activity in FNFN shale gas basins to date (the "captured case study" of gas infrastructure growth in recent years); and
- Proxy studies, preferably from other shale deposits but where necessary from examination of case studies from conventional gas sectors.

Step 4: Estimating Effects Outcomes Associated with LNG-Induced Demand on FNFN Territory

With information about the amount of additional physical works and activities required to support new wells and pads in FNFN territory, and knowledge of the nature of all these physical works and activities, the total areal, linear and other disturbance required as a result of LNG-induced gas extraction are projected. The following effects indicators were modeled based on past and current FNFN territory shale gas activities and case studies:

1. Linear disturbance (km of road, pipelines, and seismic lines);
2. Areal disturbance (hectares of land physically disturbed by gas sector facilities);
3. Water use (used in fracking of wells only);
4. Frac sands (tonnes required);
5. Frac chemical additives (litres required);
6. GHG emissions; and
7. Select social, economic and cultural effects on First Nations people.

Summary of Phase 2 Findings

This Phase 2 report finds that LNG-driven shale gas extraction of between 0.49 Mmcf/day and 2.68 Bcf/day would likely result in the following changes in the three FNFN territory shale basins during the first 20 years of a B.C. LNG export sector:

- Between 356 and 3,995 new hydraulically fractured shale gas wells;
- Development of between 30 and 333 new large industrial facilities in the form of multi-well pad complexes, each covering an average area of nine hectares;
- Between 1,440 and almost 16,000 km of new seismic lines;
- Between 150 and 1,665 km of new roads;
- Development of between 135 and as much as 3,333 km of new pipeline right of way (ROW);
- Generation of a total of between 1,635 and 20,900 km of new linear disturbance;

- Generation of total direct areal disturbance of between 30 and 375 km^2, along with a total Zone of Influence of between 104 and 1,277 km^2;
- Between one and five additional large 600 Mmcf/day sales gas plants;
- Additional GHG emissions of between 2.6 and 15.1 million tonnes per year, creating substantial challenges to B.C. meeting its legislated emissions targets;
- Water usage in the hydraulic fracturing process alone of between 11 and 320 billion litres of water drawn from FNFN territory (between 31 and 80 million litres per well);
- Use of 1.4 to 16 million tonnes of frac sands, and mining of a substantial amount of it from FNFN territory; and
- Use of 55 million to 1.6 billion litres of chemical additives in hydraulic fracturing processes; and
- Clearing for and construction of hundreds to thousands of other physical works to support the gas sector.

Adverse impact outcomes of LNG-induced gas extraction from FNFN territory may include:

- Reduced forested area in FNFN territory, increased forest loss and fragmentation and adverse effects on vegetation and wildlife reliant upon forest environments;
- Opening up of new, relatively untouched areas in FNFN territory (e.g., portions of the Liard Basin), reducing ecological and Aboriginal traditional land use;
- Loss or contamination of rare and culturally important plants and habitats;
- Reduced amount of — and functionality of - wetland complexes, critical for moose and other ungulates, furbearers, birds, and fish and other aquatic species;
- Reduced water quality and quantity and reduced riparian habitat vitality, with attendant risks for aquatic and terrestrial species;
- Increased predation of key ungulate species such as moose and woodland caribou, a Species at Risk, especially in relation to long linear developments;
- Introduction of invasive species, displacing native wildlife and vegetation;
- Increased dust and soil erosion and localized air quality effects;
- Large increases in GHG emissions, contributing to climate change;
- Increased noise, light and visual, olfactory and tactile disturbances in the areas in and around physical works and activities, affecting the population health of wildlife and increasing FNFN members' alienation from their traditional territory;
- Increased access to and use of FNFN territory by non-Aboriginal recreationalists and harvesters, increasing competition for increasingly scarce resources; and
- Increasing psycho-social impact outcomes for FNFN land users who are facing these rapid changes.

Recommendations and Closing

The analysis presented in this study clearly indicates that the scope of physical works and activities required to explore for, extract, and transport natural gas to feed export facilities and proposed pipelines in B.C., even in amounts lower than that required to meet the stated goals of the Province's *LNG Strategy*, is likely to have significant impacts on FNFN territory.

Policy recommendations are provided to enhance the way in which upstream effects are assessed, monitored and managed. Among them are:

- All elements of the LNG export sector — upstream, midstream and downstream — should be properly included in planning and environmental assessment.
- The Province should more closely examine the upstream cumulative impacts of the burgeoning LNG industry, and cumulative effects in FNFN territory in general.
- Better planning to protect portions of the Horn River and Liard Basins, especially areas of heightened value identified in FNFN's (2012) *Strategic Land Use Plan*.

The analysis clearly indicates that the scope of physical works and activities required to explore for, extract, and transport natural gas to feed export facilities and proposed pipelines in B.C., is likely to have significant impacts on FNFN territory.

The report makes a number of research recommendations, including:

- Additional scenario modeling exercises;
- Water studies to establish Aboriginal Base Flow requirements and additional research on the effects of hydraulic fracturing on water quality;
- Traditional use alienation and country food production and consumption studies;
- Gas sector impact footprint studies to expand understanding of Zones of Influence and edge effects; and
- Moose and woodland caribou population health and abundance and gas sector effects studies.

This study, like the fledgling B.C. LNG export sector itself, is preliminary and exploratory in nature. It represents an important first step in establishing the range of potential scenarios for LNG extraction on FNFN lands — and an important starting point for a serious dialogue about upstream environmental impacts of B.C.'s LNG export market ambitions. This study provides a realistic set of scenarios of future industrial change and effects that have never been projected before for FNFN territory. Multiple efforts have been made to err on the side of conservative estimates of future change. The findings of this study are 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. This study will hopefully open the eyes of other affected First Nations, the people of B.C., industry and the federal and provincial governments — to the fact that the domestic LNG export sector *ends*, but does not *begin*, on the B.C. Coast, and that impacts on upstream First Nations must be meaningfully taken into consideration during planning for a B.C. LNG future.

ACRONYMS USED IN THIS REPORT

Bcfd or Bcf/day	Billion cubic feet per day
B.C.	British Columbia
B.C. OGC or OGC	British Columbia Oil and Gas Commission
CO_2	Carbon dioxide
CO_2e	Carbon dioxide equivalent (a measure of the total emissions of a variety of GHGs)
EUR	Estimated ultimate recovery (sometimes called expected ultimate recovery)
FNFN	Fort Nelson First Nation
FNLRMP	Fort Nelson Land and Resource Management Plan
GHG	Greenhouse gases
GIS	Geographic information systems
H_2S	Hydrogen sulphide
Ha	Hectares
IP	Initial production rate for a gas well
Km	Kilometres
Km^2	Square kilometres (km/km^2 is a measure of linear disturbance density)
LNG	Liquefied natural gas
m	Metre
Mcf	Thousand cubic feet
Mcf/d	Thousand cubic feet/day
Mmcf	Million cubic feet
Mmcf/d	Million cubic feet/day
Mtpa	Million tonnes per annum
NEB	National Energy Board
ROW	Right-of-way
SARA	*Species at Risk Act*
Tcf	Trillion cubic feet
Tcf/yr	Trillion cubic feet/year
U.S. EIA	United State Energy Information Administration
VC	Valued Component
VOC	Volatile Organic Compound
WCSB	Western Canada Sedimentary Basin
ZOI	Zone of Influence

CONVERSIONS USED IN THIS REPORT

Natural gas 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 km^2 = 100 hectares
- 1 cubic metre (m^3) of liquid = 1000 litres; 1000 m^3 = 1 million litres; 1 million m^3 = 1 billion litres

SECTION 1

Introduction

1.1 STUDY CONTEXT AND PURPOSE

Fort Nelson First Nation (FNFN or the Nation) is a traditional hunting/gathering Dene/Cree society of roughly 860 members that has lived for countless generations in the boreal forest of northeastern British Columbia.

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 by FNFN members are subject to many new pressures.

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.

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.

FNFN territory encompasses some of the largest natural gas reserves in the Western Canada Sedimentary Basin (WCSB) and some of the largest proven shale gas resources the world. Shale basins in FNFN territory include the Horn River Basin, the Cordova Embayment, and the Liard Basin. Together, they cover 36,690 km^2, almost half of FNFN's core territory (see Figure 5). 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.

Minimal work has been conducted to date to evaluate the upstream implications of fueling the B.C. LNG export sector. 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 resources.

This study represents the first attempt by any party to look at potential effects of LNG export scenarios on the air, water, land, wildlife and Treaty rights holders in FNFN territory. 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.

The following research questions guided the study:

- Phase 1: What B.C. LNG export-induced natural gas production growth scenarios are likely for the WCSB and the three shale gas basins in FNFN territory (Horn River and Liard Basins and the Cordova Embayment)?; and
- Phase 2: What changes will these different LNG-induced gas growth scenarios likely cause on FNFN territory, in terms of additional industrial activity levels and environmental effects?

1.2 PHASE 1 FINDINGS[1]

Phase 1 developed a range of realistic scenarios of how much natural gas will be extracted from FNFN territory to feed the B.C. LNG export sector. 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 range of realistic scenarios 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 realistic range of the amount of gas from FNFN territory that will be used to fuel the B.C. LNG export market.

Table 1 brings together the two main findings of the Phase 1 report (low and high B.C. LNG export scenarios and the proportion likely to come from FNFN territory basins) to provide a series of potential LNG-induced gas extraction scenarios for FNFN territory, measured in billion cubic feet per day (Bcf/day).

1 The Phase 1 Report (MacDonald 2014) is available from FNFN Lands Department or at www.thefirelightgroup.com.

Table 1: 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
Note: This table includes only new gas production required to support LNG exports, not to supply North American markets.		

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 (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, these average amounts of production per year would equate to between 3.56 and 19.5 trillion cubic feet (Tcf) of LNG-induced gas extraction from FNFN territory. These scenarios would see significant increases in the amount of gas produced from FNFN territory over historic and current numbers. The lowest LNG-induced gas extraction scenario for FNFN territory would be 160 per cent more than 2012 gas production levels from shale deposits in FNFN territory of 0.28 Bcf/day. At the high end of the realistic scenario scale, that number jumps to an almost 10-fold increase. It is readily apparent that even with conservative (low end) estimates, the B.C. LNG export sector will induce significant additional gas sector activity in FNFN territory.

1.3 PHASE 2 PURPOSE

Armed with realistic scenarios of how much growth in gas extraction from FNFN lands would be caused by development of a B.C. LNG export sector, Phase 2 of this study focuses on estimating how this will change FNFN territory. Within this range of LNG-induced gas extraction, environmental and socio-economic implications for FNFN can be modeled using change to date in FNFN territory and proxy studies of impacts of shale gas from other jurisdictions as triangulation sources, among other tools. This work includes development of estimates of likely infrastructure requirements on a per well and per well pad basis, and estimating linear and areal disturbance levels that would likely result on the ground in FNFN territory, among other measures of change.

Questions guiding this Phase 2 study were:

- What types of effects are caused by upstream gas sector activities?
- What effects have already been caused by upstream gas activity in FNFN territory?
- In light of the Phase 1 LNG-induced gas extraction scenario findings, what range of additional physical works and activity can be expected in FNFN territory in the first 20 years of an LNG export sector?
- What are some of the likely environmental and socio-economic effects of this additional industrial development in FNFN territory?

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 indicate the need for further more detailed work on scenarios of change linking upstream gas development in northeastern B.C. to the fledgling B.C. LNG export sector.

1.4 REPORT STRUCTURE

This report is structured as follows:

- Section 2 describes the methods used, limitations and assumptions of Phase 2;
- Section 3 provides an introduction to the types of impacts upstream natural gas industry physical works and activities can have, and have had in FNFN territory to date;
- Section 4 develops scenarios, triangulated from a variety of sources, of the amount of wells, well pads and other physical works and activities required to fuel LNG-induced gas extraction in FNFN territory over the first 20 years of a B.C. LNG export sector;
- Section 5 identifies some of the potential resultant environmental (and other) impacts of LNG-induced gas extraction on FNFN territory; and
- Section 6 summarizes findings and implications of both phases of the study and offers recommendations for further work and policy changes.

SECTION 2

Phase 2 Study Methods

Phase 2 of the study estimates required physical works and activities and attendant environmental impacts of the LNG-induced gas extraction scenarios developed in Phase 1, including but not limited to impacts such as:

- Kilometres (km) of new roads, pipeline and seismic lines required, and associated linear disturbance;
- Number and size of new well pads and facilities required in support of the gas sector, and associated areal disturbance;
- Billions of litres of water and other process additives required to support hydraulic fracturing; and
- GHG emissions.

The methods used to model these potential changes are provided below.

Phase 1 indicates that B.C.'s LNG sector will require extraction of between 490 million cubic feet per day (Mmcf/day) and 2.68 billion cubic feet of gas per day (Bcf/day) from FNFN territory from 2018 to 2038. Phase 2 sheds light on how the B.C. LNG export sector will impact FNFN territory.

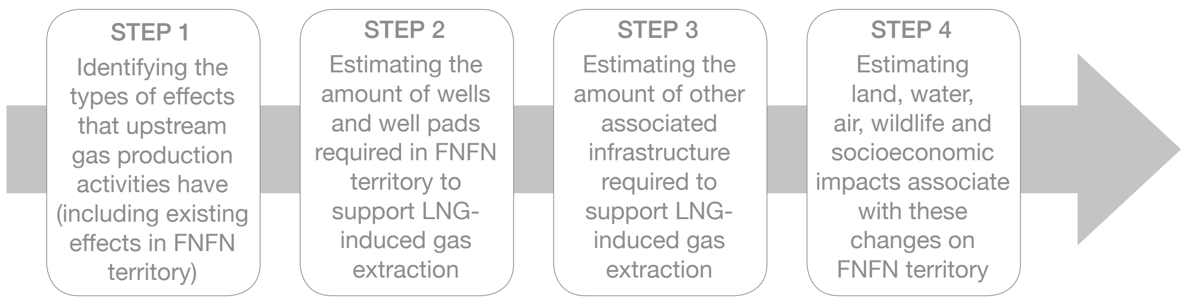
2.1 PHASE 2 STUDY APPROACH, METHODS AND INPUTS

Phase 2 of this study sheds light on how the B.C. LNG export sector will impact FNFN territory.

A critical first element — the range of gas required — is already in place. The results of Phase 1 indicate that B.C.'s LNG sector will require extraction of between 490 million cubic feet per day (Mmcf/day) and 2.68 billion cubic feet of gas per day (Bcf/day) from FNFN territory from 2018 to 2038.

To determine what sort of impact outcomes that may lead to in FNFN territory, the author conducted the following four steps in Phase 2.

Figure 1: Steps for Estimating the Physical Impacts of the Gas Production Forecasts from Phase 1



Step 1: Identify elements and effects of the upstream gas industry (Section 3)

Section 3 of this report uses secondary data (industry data, B.C. Oil and Gas Commission (B.C. OGC) data, academic and other research) to identify:

- Key physical works and activities involved in the upstream (exploration, production and initial transportation toward market) unconventional gas sector;
- Impacts associated with the upstream unconventional gas sector; and
- How much gas sector works and activities have occurred in shale basins in FNFN territory to date, and some of the associated impacts.

This information is used to guide identification of key gas sector works and activities and effects caused by them, to be further assessed when modeling the outcomes of LNG-induced demand in Sections 4 and 5. The effects to date in FNFN territory, in particular, are a useful "captured case study."

Step 2: Estimating Gas Wells and Pads Required in FNFN Territory in LNG-induced Gas Extraction Scenarios (Sections 4.1 and 4.2)

Sections 4.1 and 4.2 of this report estimate a range of how much gas is likely to be produced per well and per well pad in FNFN territory. It does so based on existing published data from academic, industry and government sources. A couple of factors are critical in this estimation:

1. **ESTIMATED ULTIMATE RECOVERY (EUR) PER WELL —** The amount of gas expected per hydraulically fractured shale gas well over its lifetime, typically measured in Bcf.
2. **DECLINE RATE —** The speed at which the production of a gas well, highest at the beginning of the productive life of the well, declines. This is typically measured by the percentage by which production levels decline per year. The decline rate of gas wells means that in order to maintain a steady flow of gas, new wells continually have to be developed. Studies like Hughes (2014) take this decline rate into account when estimating the number of total wells required over a set time period for a specified supply of gas.

Using the above parameters, this report where necessary has adjusted the estimates of other studies based on different per well characteristics, to fit those more likely to occur in FNFN territory (which has higher EUR and faster decline rates than average WCSB wells).

Section 4.2 of the report estimates a range of the amount of wells and well pads required in FNFN territory to satiate LNG-induced gas extraction over the first 20 years of the B.C. LNG export sector. It does so by using several different proxy studies and estimates of current and future gas production per well from FNFN territory to generate a range of estimates for the number of required wells and pads. The type of sources materials used included:

1. The current amount of wells per unit of production in B.C. and FNFN territory;
2. Extrapolation from EUR estimates per well in FNFN territory (e.g., OGC 2013a);
3. Modeling by FNFN territory producers (Apache Corporation in the Liard and Horn River Basins);
4. Specific estimates of future wells required in B.C. to fuel LNG-induced demand (e.g., Hughes 2014; Walden and Walden 2012); and
5. Estimates from other shale gas jurisdictions (e.g., Ziff Energy Group 2012; Mason 2011).

Each individual triangulation tool has strengths and limitations that are laid out in section 4.2. In every instance, the wells per unit of production findings from these different studies were filtered through the high and low Bcf/day gas extraction scenarios developed in the Phase 1 report. The outcome is a set of thirteen scenarios of potential future wells and pads required in FNFN territory to support LNG-induced gas requirements between 2018 and 2038.

Using the resulting range of the number of wells required during the first 20 years of B.C. LNG export-induced production, the report estimates what additional infrastructure and inputs are required to support that number of wells. The first important calculation is to estimate how many wells will be developed per well pad. In the past, one well = one pad was the typical formula for vertical well, conventional gas sources. New technologies, however, mean that multiple wells per pad have rapidly become the norm. This study assumes 12 wells per pad (see Section 4.2.6). Given the growth of multiple wells being drilled from the same physical location — a single wellpad complex — much of the additional infrastructure, typically measured or modeled in the past on a "per well" basis, should now be measured on a "per well pad" basis. Exceptions include inputs that occur for each well, such as water and frac sands/additives.

Step 3: Estimating the Amount of Other Physical Works and Activities Required (Section 4.3)

Section 4.3 then estimates the average amount of infrastructure required per well or well pad triangulated from a couple of key inputs:

- Activity in FNFN shale gas basins to date (the "captured case study" of gas infrastructure growth in recent years); and
- Proxy studies, preferably from other shale deposits but where necessary from examination of case studies from conventional gas sectors.

FNFN territory has encountered rapid shale gas sector activity growth over the past five to ten years, as described in some detail in section 3.3. One of the triangulation tools used to estimate future physical works and activity requirements was to identify the amount of physical infrastructure required per wells/well pads in FNFN territory during the 2006–2013 period, gathered primarily using B.C. OGC's online database (www.bcogc.ca/public-zone/gis-data). The author worked with FNFN Lands Department's GIS Technician to determine total physical works by type (e.g., roads, pipelines, facilities) during that time period in shale basins in FNFN territory to help calculate "per well" or "per well pad" relationships.

Limits on the Use of Case Study Materials

Much has changed in recent years in the natural gas production sector, in North America and in FNFN territory. There has been a transition from dedicated, single well pads in relatively small clearings, to larger (but potentially smaller per well footprint) multi-well pads. Horizontal drilling has largely replaced vertical drilling and horizontal fracturing into unconsolidated and unconventional (e.g., shale) reservoirs are now the dominant extraction method and targets, respectively. These changes make problematic the reliance on previous case study materials, almost all of which focused on conventional gas development, as proxies for likely future development. Modeling studies on the Mackenzie Gas Project (e.g., Cizek: 2005); Peele River in the Yukon (Holroyd and Retzer 2005); among others, are largely outdated because:

- Estimates of linear disturbance per wells were based on single, not multi-well, pads;
- Water use has skyrocketed, as has the use of fracking chemicals and other inputs;
- Both the EUR and decline rates are typically higher in unconventional deposits than in past conventional deposits;
- The amount of space used up for a single well pad complex is now quite a bit larger than it was for a single well conventional pad; and
- Seismic line clearing technologies have changed, with narrower and non-straight lines reducing environmental impacts on a per unit basis.

Those changes have been taken into consideration in this effects modeling exercise. Previous studies that focused on the amount of effects likely to occur in conventional basins are approached with caution, any factors reducing confidence in their applicability clearly identified, and every effort made to gather information relevant to current technologies. In order to further overcome inevitable compatibility obstacles, the author also:

1. Searched for relevant shale gas technology effects outcomes examples;
2. Used information from recent shale gas activity in FNFN territory as a "captured case study"; and
3. Triangulated potential well numbers from a wide variety of available secondary sources.

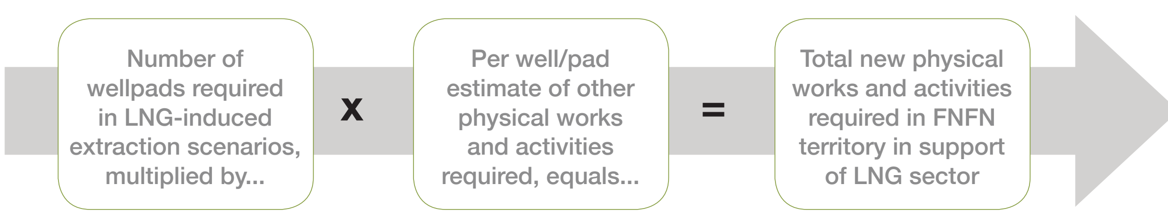
In addition to describing the amount of these activities to date in FNFN's three shale gas basins, other proxy studies were considered that estimated the required amounts of development of these physical works on a per well or other per unit basis. Those studies included Holroyd and Retzer (2005); Government of Yukon (2005); and Johnson et al. (2010).

Triangulating data from both sets of tools, average per well/pad metrics were developed for the following physical works and activities required in the upstream gas sector:

- Pipelines (km);
- Roads (km);
- Seismic lines (km);
- Gas plants (number);
- Compressor stations (number);
- Dugouts and other water gathering, storage, and treatment facilities;
- Work camps;
- Drill rigs (active at any one time); and
- Borrow sites.

The figure below illustrates how the total amount of required physical works and activities required to support LNG-induced gas extraction from FNFN territory was then estimated.

Figure 2: How Physical Works and Activities Required to Support LNG Extraction Was Estimated



In a hypothetical example, if 1,000 wells are expected in FNFN territory to generate the gas required to fuel the LNG sector, and there is a typical relationship of about 2.5 km of new road per well, then it can be estimated that an additional 2,500 km of new road will be required in FNFN territory in support of LNG-induced gas extraction.

Step 4: Estimating some of the effects outcomes on FNFN Territory of LNG-induced gas requirements (Section 5)

With information about the amount of additional physical works and activities required to support new wells and pads in FNFN territory, and knowledge of the nature of all these physical works and activities, the total areal, linear and other disturbance required as a result of LNG-induced gas extraction can be estimated.

Through examination of the upstream gas sector (Step 1), the author identified the following effects indicators (physical effects and process inputs and outputs) that can be modeled with reasonable confidence based on past and current FNFN territory shale gas activities (the majority of it hydraulic fracturing based), and case studies from other jurisdictions:

1. Linear disturbance (km of road, pipelines, and seismic lines);
2. Areal disturbance (hectares of land physically disturbed by well pads, facilities, and other disturbances);
3. Water use (used in fracking of wells only; additional requirements in support of the gas sector are not estimated herein);
4. Frac sands (tonnes required);
5. Frac chemical additives (litres required);
6. GHG emissions; and
7. Select social, economic and cultural effects on First Nations people.

The indicators chosen are not the only indicators of change but cover land, water, and air components important to FNFN and its members. Some discussion is provided on the implications of increased disturbance levels on FNFN territory on critical biophysical and human environmental Valued Components (VCs) in Sections 5.2 and 5.3, but further work will be required to estimate LNG-specific and cumulative gas sector effects on wildlife, fish, and other VCs.

The author focused on finding credible "per unit of physical work and activity" land and input use data and multiplying this by the expected number of those physical works and activities required in the LNG-induced gas extraction scenarios identified in the Phase 1 report. In another hypothetical example, given that the typical large multi-well complex covers some nine hectares, if there are 75 well complexes required, that particular land use would be expected to be (9 * 75 = 675 hectares).

Data that could be characterized in terms of area, such as well pad complexes and other facilities, use hectares (ha) and square kilometres (km^2) as their primary metrics. Data that can more effectively be characterized as linear disturbances are in total km and sometimes kilometres per square kilometre (km/km^2).

2.2 PHASE 2 STUDY LIMITATIONS AND ASSUMPTIONS

Any forward-looking scenarios study like this one is subject to fundamental limitations. As noted in Johnson et al. (2010), “energy projections are informed scenarios — not predictions.” No one scenario of a future outcome is “most likely” with the many variables in play. Instead, a set of possible futures of natural gas activities are provided herein. Even where the author suggests a certain range of outcomes is subject to higher confidence, each scenario should be considered equally possible and incorporated into management planning.

2.2.1 Study Limitations

- This study is limited only to gas development within FNFN’s three shale gas basins. Effects of gas production in other portions of FNFN territory, including the northern-most portion of the Montney shale/tight gas formation, the “erosional edge” of which enters into FNFN territory (see Figure 1 in the Phase 1 report), are not considered. This makes estimations lower than the total effects of LNG-induced gas extraction on FNFN territory.
- This is not a comprehensive cumulative effects assessment. It is rather a forward looking scenario analysis. While some of the existing effects of gas activity on FNFN territory are identified and discussed, their effects are not added to those likely to occur in an LNG future. Nor are the effects of continued domestic and North American market driven gas development on FNFN territory considered. In addition, this study calculates only effects of natural gas sector related disturbance, not that of any other industrial activities (e.g., forestry) or other anthropogenic change. A detailed cumulative effects assessment will be required to identify total anthropogenic change in FNFN territory and the effects of same on a series of VCs.
- The study is limited to the time period 2018-2038, projected to be the first two decades of B.C. LNG exports. Physical works and activities and associated environmental effects that are generated after this period are not accounted for herein, despite the likely extension of the sector far beyond this initial period.
- By design, this study is based on extrapolation of potential future change based almost exclusively on review and analysis of secondary data, not an independent technical “wells required” modeling exercise.
- Numbers are gross and not location specific. The study does not estimate the proportional distribution of future activity levels between the three FNFN basins, nor does it predict where exactly on the ground the impacts will occur within each basin. Spatial distribution of development features is not predicted nor represented herein. This study only identifies a range of potential quantities of development features across the three FNFN shale gas basins.
- This is not an economic study. No economic cost estimates were made as part of this exercise, nor is any judgment expressed about the balance of economic and other interests.
- The numbers used herein represent triangulated analysis from multiple sources. Nonetheless, there is variability in the resource that could alter the actual production per well and well pad from the scenarios identified herein, either up or down.

2.2.2 Assumptions

The above-noted limitations made the development of clear, defensible and transparent assumptions to guide the study critical. They include:

- The amount of new physical works and activities required will be limited to the amount necessary to support the LNG-induced gas extraction scenarios in the Phase 1 report, of between 0.49 and 2.68 Bcf/day over the period between 2018 and 2038. All of the relevant assumptions used to estimate that range of gas production attributable to LNG demand are provided in Section 3.2 of the Phase 1 report (MacDonald 2014). It is assumed that there will be sufficient economic incentive and capital investment to drive this level of LNG-induced growth in FNFN territory.
- Full production will be maintained (at between 0.49 and 2.68 Bcf/day) for the entire period between 2018 and 2038. No "ramp up" or "tail end" production decline is estimated; a 20 year consistent average is assumed. This study, as a result, reflects a reasonable approximation only of the first 20 years of effects of the B.C. LNG export sector on FNFN territory. There is every reason to believe that production will continue after 20 years because of sunk costs, marketing arrangements with offshore buyers, and ample remaining FNFN gas supply.
- Wells drilled to maintain current production levels, all of which goes to North American markets, are not considered herein. No estimation is included of the amount of wells and other physical works and activities required to support continuation or expansion of exploration, development and production/transportation for domestic or North American markets. Given that both new domestic demand sources/amounts may emerge and the conservative nature of the Phase 1 LNG-induced gas extraction estimates, this estimate is conservative and will likely reflect only a portion of the total effects load of additional gas development activity in FNFN territory during the identified time period.
- All LNG-induced demand will be satisfied through new wells on top of existing ones, not tapping of existing reserves from pre-drilled and readily accessible wells that are currently waiting for a viable price to make them economic. If there are existing reserves at existing wells that have yet to be extracted (e.g., due to a lack of economic feasibility during a downturn in gas price), it is assumed that these reserves, if extracted, will be committed to current domestic and North American customer bases, not offshore LNG markets.
- All new well pads will be unconventional multi-well and horizontally drilled hydraulic fracturing arrangements, averaging 12 wells per pad (see Section 4.2.6 for more discussion). This assumption is respectful of changing technologies.
- Neither shrinkage (12 to 19 per cent of totals in FNFN territory (KM LNG 2010)) nor gas used in production, transportation and liquefaction (another 10 per cent of totals — U.S. EIA 2012) are included in the assessment. Thus, the estimates of wells, other physical works and activities — and by extension impact loads — are likely underestimated by approximately 20 to 30 per cent.

Even with these limitations and assumptions, this study provides a realistic set of scenarios of future industrial change and effects that have never been illustrated before for FNFN territory. Multiple efforts have been made to err on the side of conservative estimates of future change. Nonetheless, the author encourages other parties to apply themselves to refining these methods and to develop their own scenarios of future change associated with LNG-induced demand for First Nations territories in northeastern B.C. This study was designed to open a door of enquiry, not close one.

SECTION 3

Effects of Upstream Gas Activities

This section of the report identifies components of the natural gas production system that occur in northeastern B.C., and identifies some of the effects these physical works and activities can have in general, and have had in FNFN territory to date.

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3.1 THE UNCONVENTIONAL NATURAL GAS PRODUCTION SYSTEM

Described below are some of the critical physical works and activities required in order to produce and transport towards market natural gas extracted through the hydraulic fracturing of shale deposits.

- At the outset of exploration, **seismic lines** are linear clearings cut through the forest to conduct geophysical exploration to indicate the location and character of gas formations below the surface. Previously cut using a bulldozer ("cat cut"), in the past decade low impact seismic has become more common with areas cleared manually or using mulchers, and meandering rather than straight lines to reduce line of sight for predators. The lines can be anywhere from 1.5 to 5 metres in width.
- When a highly prospective area is delineated from geophysical studies and modeling, the area is opened up via **road building**, for transport of equipment and workers. Gas industry roads rights-of-way (ROW) are typically between 10 and 30 metres wide, depending on whether they are smaller spur roads or arterial roads connecting to main transportation corridors.
- Clearings are developed in the forest for leveling and development of **wellpad complexe**s. In the past, for conventional wells, there was a one well per well pad on a cleared area of about one to three hectares. More recent wellpads have a much larger footprint (up to 16 hectares, the equivalent of a 400 by 400 metre square), but reduce the overall number of wellpads in given area. Figure 3 below shows a shale gas well pad complex in FNFN territory (from B.C. OGC 2013c).

Figure 3: Example Multi-Well Pad Complex in Northeastern B.C. (B.C. OGC 2013c)

- **Wells** are drilled — for gas, water inputs, and in some cases deep disposal wells for produced water. The most time, labour, process inputs and cost intensive wells are the gas wells themselves. Large, specialized drill rigs are transported to the well pad complex via road and drilling ensues.

- **Hydraulic fracturing** of the wells occurs. This process is described in Section 2.1 of the Phase 1 report for this study. Typically, each well is hydraulically fractured (or "stimulated") a series of times in order to maximize initial flow rate and overall production of gas from the well. This involves a large amount of physical works and activities. A large amount of vehicle movement, water withdrawals and inputs into the well, frac sands and other additives, are involved in this process.

- To transport the gas from the well pad complex, **feeder pipelines** and larger **raw gas trunk pipelines** send gas to a raw-to-sales gas processing facility and to market through a larger **sales gas pipeline** beyond (B.C. OGC 2013b). Development of these pipelines will occur either along existing rights of way (ROW) such as roads, or in some cases through "new cut" — additional linear clearing through forested areas. Water crossings will also be required for pipelines. These may be through tunneling under a watercourse or by short-term diversion of the watercourse ("open cut") during construction. Smaller feeder lines may travel along existing ROW and likely require minimal additional clearing. Large trunk lines and especially sales gas pipelines may require extensive new clearing and ROW of between 15 and 50 metres width (for example, new cut proposed for the Komie North pipeline through the Horn River Basin was estimated at an average of 30 metres — NGTL 2011). They require highly labour and equipment intensive construction periods that may last two or more years. Their effects are felt for long periods of time, with active management to avoid reforestation along portions of the ROW during the life of the pipeline, which may exceed 50 years.

- B.C. OGC (2013c, 9) defines required upstream gas **supporting facilities** as "systems of vessels, piping, valves and other equipment used to gather, process, measure, store and/or dispose of petroleum, gas, water and waste." They include batteries for storage of liquids, dehydrators, flare sites and metering sites. Also, in addition to raw and sales gas pipelines, a large amount of above ground and underground **flowlines** are required, transporting water, process additives and materials removed from the gas (e.g., hydrogen sulphide, or H_2S).

Figure 4: Cabin Gas Plant (currently under construction)

PHOTO COURTESY KATHERINE WOLFENDEN

- Large gas pipelines also require **compressor stations**. Compressor stations generate power (typically using a portion of the gas stream) to increase the pressure of the gas in the pipe to maintain flow of the gas toward market.
- **Gas plants** are large industrial facilities that remove H_2S, $C0_2$, water and other “impurities” from raw gas prior to them entering sales gas pipelines. Gas plants can be of many sizes. For example, the currently proposed Fortune Creek Gas Plant would cover 78 hectares and be able to process 600 million cubic feet of gas per day. One of the major “impurities” removed at FNFN territory gas plants is CO_2, which is in much higher amounts in raw gas than in other B.C. unconventional gas sources (e.g., Horn River CO_2 averages 12 per cent of raw gas). Currently, this CO_2 is vented directly to the atmosphere. Figure 4 of the Cabin Gas Plant, currently being developed in FNFN territory, is illustrative of the large spatial extent of such facilities.
- **Water gathering, storage and management/treatment facilities** are also required, and can be substantial in number and size. These include ground water wells, water storage pits (dugouts) and deep well disposal sites.
- **Borrow sites** for granular materials (e.g., for road building and site stabilization) and, increasingly, “frac sands” — the main proppant used in fracking being fine grained sands required by the thousands of metric tonnes per well.
- **Transportation** of large amounts of water, frac sands, process additives and equipment are required, as are large numbers of crew transport trips, by plane, helicopter, and road.
- **Work camps** are required to house the primarily out-of-region workforce.
- In some cases, **power transmission lines** may also be placed above or underground to power the industrial facilities of the gas sector (B.C. Hydro 2013).

3.2 ENVIRONMENTAL AND OTHER EFFECTS OF THE UPSTREAM GAS SECTOR

A note on economic benefits: B.C. government and industry focus has been on economic benefits of the B.C. natural gas sector. These are estimated elsewhere (see for example Ernst & Young 2013b; B.C. Jobs Plan 2013; B.C. Ministry of Energy and Mines 2012 and 2013; Grant Thornton LLP 2013a and 2013b), and are not the focus herein. The focus in this study is to move environmental and other impacts and risks of the proposed B.C. LNG export sector into the discussion.

The above-noted gas exploration, development, extraction and transportation activities bring with them a series of potential environmental concerns. A few of the many effects of the upstream gas sector are discussed in more detail below. For more detailed analysis of potential upstream gas effects, see Environmental Law Centre (2013) and Campbell and Horne (2011).

3.2.1 Effects on Wildlife

Shale gas activities can have multiple effects on wildlife, including direct impacts (e.g., wildlife will no longer be able to use the areas in and around the project footprint, roads will impact mortality and use) and indirect impacts (e.g., impacts on air and water quality may affect wildlife health). A summary of overarching concerns on wildlife is provided below.

Overarching wildlife concerns

Shale gas development directly removes habitat from the project footprint, and results in a substantial increase in linear features across the landscape, including seismic lines, pipelines, and roads. Linear corridors remove habitat and improve sight lines for predators, putting increased pressure on wildlife populations. Roads that are built to support shale gas production make it easier for people to access areas that were previously remote—and more hunters means more harvesting pressure on key wildlife populations. Increases in traffic can also result in increased mortality of wildlife within the area from collisions with vehicles.

Habitat impacts are usually felt more broadly than the specific footprint of the industry, as noise and other sensory disturbances from the development will cause some wildlife to avoid the area. In some cases, the extra energy wildlife use to avoid industrial sites and clearings can result in increased morbidity and mortality and lower reproductive success (see discussion on woodland caribou below).

Air emissions from shale gas production and impacts on water quality can also have an impact on wildlife, both in terms of contaminating the meat of animals that are hunted, and increasing the incidence of disease for some wildlife species.

Disturbances like shale gas development can facilitate the development of ecological change and introduction of disturbance-tolerant species. As populations of species sensitive to disturbance decrease, populations of species tolerant to disturbance (such as coyote and deer—two non-preferred species for FNFN) increase (Neilsen et al*.* 2007).

Grizzly (and other) bears

Grizzlies, in particular, require large areas of connected habitat to sustain populations over the long-term. Gas activities threaten this connectedness and also increase human-bear interactions through increased numbers of people in the area and more roads—usually with negative outcomes for bears (Environmental Law Centre 2013).

Moose

Oil and gas development removes forest cover, and improved sight lines for predators and hunters alike can increase predation on moose. Road infrastructure associated with oil and gas development will increase access into the area, putting increased harvesting pressure on moose populations. Effects on wetland habitat (see below) will also impact moose, since they spend much of their foraging time in these habitats. A related concern is the potential for moose contamination through exposure to water sources polluted by hydrocarbons (e.g., SFN and WMFN no date).

Woodland caribou

Woodland caribou is a SARA-listed species[2] that requires large, undisturbed areas of habitat to survive. Research links population declines of caribou with increases in natural and anthropogenic disturbances—and it appears that they are sensitive to these disturbances within 500 metres of industrial developments (Environment Canada 2011 — some other key metrics from the scientific literature are noted in the text box). Caribou are vulnerable to predation along long, linear ROWs and thus avoid them as well as cleared well pads (Dyer et al. 2001). Because of their sensitivity to disturbance, a number of studies have examined thresholds of disturbance that are likely to cause decline of woodland caribou.

Woodland caribou disturbance thresholds

Research indicates:

- Woodland caribou populations decline when more than 50 per cent of the range is disturbed (Anderson et al. 2002).
- Core area patch size should average greater than 5000 hectares (Forest Practices Board 2011).
- Caribou populations may decline when linear corridor density exceeds 1.8 km/km^2 (Francis et al. 2002). Salmo Consulting Inc. et al. (2004) suggest a threshold of 1.5 km/km^2. Simulation modelling identifies that caribou would be extirpated in areas where corridor frequencies exceed 1.22 km/km^2 (Weclaw and Hudson 2004).
- Caribou would be extirpated from northern Alberta in less than 40 years if linear densities exceed 1.2 km/km^2 (reported in Schneider and Dyer 2006).

2 In the federal *Species at Risk Act*, woodland caribou (boreal population) are listed as threatened (www.sararegistry.gc.ca/default_e.cfm).

FNFN has already published data showing linear disturbance rates well above the identified thresholds through large portions of FNFN territory, including in core caribou habitat areas (Lowe and Tate 2013; FNFN 2013). Activities associated with shale gas exploration and development have, and will continue to create, additional sensory and linear disturbances that strongly impact caribou.

Furbearers

Populations of lynx, marten, fisher and other furbearers have been shown to decline significantly in regions subjected to industrial development (Schneider and Dyer 2006). Decline rates are strongly correlated with road density (Nielsen et al*.* 2007).

Birds

Bird species in the boreal forest have been found to be sensitive to industrial disturbance, and in some cases they may be at increased risk of mortality and morbidity from these developments. Many forest bird species avoid using habitat within 100 metres of roads, pipelines, well pads and other gas industry facilities (Cumming and Schmiegelow 2004).

3.2.2 Effects on Habitat and Vegetation

The development of shale gas infrastructure directly removes habitat and vegetation, and may have indirect effects on adjacent habitat by increasing light penetration into surrounding forests, changing hydrologic conditions, and increasing the potential for invasive plant establishment. Some of the major gas sector effects on habitat and vegetation are described below.

Reduction in forested landbase

> *Imagine, three massive pipelines with the required right of ways all within close proximity and all carrying the same product. Now layer on the tens of thousands of kilometres of 2.7 metre cut lines for the seismic programs, the thousands of 1-acre well pads, the thousands of kilometres of feeder pipelines, roads, compressor stations and gas plants. Then consider issues associated with the use of millions of cubic metres of water for fracking and the impact of wildlife, the forests and surrounding areas in Fort Nelson. — Sharon Glover (2013, 7), CEO of the Association of B.C. Forest Professionals, on concerns about effects of an LNG export sector on cumulative impacts on northeastern B.C.'s forested landbase*

Forest fragmentation can be defined as the process of division of original forested landscape up into smaller sections (largely through introduction of lines/breaks in the forest from industrial activities), which results in the loss of original habitat, reduction in the size of continuous forest and an increase in isolation of "patches" of forest that may not have the same ecosystem health status and reduced ability to support native species (Andren 1994).

Shale gas has an immediate impact on the total linear and areal disturbance of forested lands. The land clearing required for shale gas infrastructure, including roads, seismic lines, well pads, and pipeline networks, contributes heavily to habitat fragmentation, and is perhaps the most significant contributor to cumulative effects on the biophysical environment in northeastern B.C.

With this removal of forest, habitat is lost for fish, game, birds and vegetation. Fragmented habitat is detrimental to wildlife because individual mortality increases for animals moving between patches and re-colonization rates are lower, both of which can result in lower population. Forest clearing leads to new forest edges, where predation, changes in light and humidity, and the expanded presence of invasive species can threaten forest interior spaces well beyond the physical footprint of gas projects. Johnson et al. (2010) suggest the following relationship for direct and indirect impacts of areas cleared by shale gas development in the Marcellus Shale in the northeastern U.S. For every 3.1 acres of forest cleared for a single well pad:

- An additional 5.7 acres of forest is cleared for associated infrastructure such as roads, pipelines, and water containment pits;
- A total of 8.8 acres of total forest is cleared; and
- Indirect forest impacts from the development of new edges are felt in another 21.2 acres of forested landscape (2.41 times the direct disturbance area).

In total, a 3.1 acre well pad clearing is estimated by Johnson et al. (2010) to impact on a total of 30 acres, or almost nine additional acres of direct and indirect adverse effects for every acre of well pad clearing.

Clearing for gas activities can lead to a reduction in average forest age. Research indicates that in gas production intensive regions, species adapted to younger forest types have thrived in comparison to those specialized to older forest types (Schneider 2002), and species that rely upon continuous forests have decreased versus those adapted to fragmented landscapes (MacFarlane 2003). These two factors in combination mean that gas activities can lead to long term net reductions in species diversity and distribution in gas producing areas.

Research has also shown that forest regeneration may be slow on seismic lines. Studies in northern Alberta have shown that only 11.9 per cent of seismic lines that have been inactive for over 20 years have sufficiently regrown to be considered regenerated forest lands (Schneider: 2002).[3] Some seismic lines are re-cleared in later years for more exploration or get upgraded to roads, extending the time length of effects.

Impacts on soil

Disturbances associated with shale gas development, including increased erosion and changed sedimentation patterns, can have a noticeable impact on soil productivity. ROW clearing and roads are among the culprits, with soil compaction impeding vegetation regrowth.

Impacts on vegetation distribution and health

Shale gas development and associated infrastructure can reduce plant and ecosystem diversity, contaminate individual plants, remove rare plant species, and impact tree health (Sample and Price 2011). These impacts are caused by the direct effects of land clearing, changes in local air quality, by an increase in invasive plants and through the increased risk of toxic spills near oil and gas developments. Seismic lines may encourage all-terrain vehicle traffic, lengthening the period of time it takes for natural forest cover re-vegetation.

3 Another Canadian study found that 65 per cent of seismic lines cut three decades ago were still in a cleared state (Lee and Boutin 2006). However, in recent years seismic lines are much narrower and generally structured to reduce line of site issues re: predation and to facilitate more rapid regrowth than in the past.

3.2.3 Effects on Air Quality and Climate

Greenhouse Gas Emissions and Climate Change

> *"The GHG footprint of shale gas is significantly larger than that from conventional gas… The larger GHG footprint of shale gas undercuts the logic of its use as a bridging fuel over coming decades, if the goal is to reduce global warming" — Howarth et al. (2011, 688)*

The effects of shale gas production on greenhouse gas emissions (GHGs) — gases that are known contributors to climate change—may be higher than originally thought (Howarth et al. 2011; The Pembina Institute 2013; Campbell and Horne 2011). While people tend to associate natural gas with being cleaner than oil or coal, some full life cycle analyses of shale gas fracking are finding different results. Methane is the main component of natural gas, and can leak from the wellbore into groundwater and other near surface or surface areas. Howarth et al*.* (2011) suggest that 3.6 to 7.9 per cent of methane from shale gas production escapes to the atmosphere in venting and leaks over the lifetime of a well.[4] At this rate, shale gas production can result in at least 30 per cent—perhaps more than 50 per cent—higher GHG emissions than conventional gas wells. As one study put it, "the cleanest-burning fossil fuel might not be much better than coal when it comes to climate change" (Tollefson 2012).

In addition to fugitive methane emissions, a specific concern within the Horn River Basin is the high carbon dioxide (CO_2) proportion in gas from this area (+/- 12 per cent)[5], especially given that this GHG is permitted under the current B.C. regulatory regime to be directly vented to the atmosphere at gas plants. On top of these direct emissions of GHGs, forest cover removal and vehicle and equipment emissions required for development of shale gas plays also contributes to climate change.

Air Quality Impacts

Many respondents in a Fraser Basin Council (2012, 25-26) study on human health concerns related to the northeast B.C. gas sector identified air quality concerns. Hydraulic fracturing to release shale gas results in increased emissions of volatile organic compounds (VOCs) and hazardous air pollutants into the atmosphere. Emissions from sweet gas include benzene, toluene, xylene and dioxins, while natural gas flares may also release carbon particles, unburned hydrocarbons, carbon monoxide, nitrogen oxides and sulfur dioxide. Toxic VOCs may travel long distances on ambient wind, producing a wide spread sensory and—potentially—health impact on both wildlife and land users.

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4 It should be noted that "reduced emission completions" technology can reduce these emissions by up to 90 per cent.

5 These numbers are slightly lower for Liard Basin and Cordova Embayment, but their 7 to 8 per cent CO_2 proportions are still well above WCSB and North American shale gas averages (B.C. OGC 2013b).

3.2.4 Effects on Water and Aquatics

The concerns regarding impacts of shale gas development on water have been well documented. They are grouped below into a number of categories, including water quantity, water contamination, impacts to fish and fish habitat, and effects on wetlands.

Water quantity

Hydraulic fracturing requires massive amounts of water—much more than conventional gas—especially in shale basins like those present in FNFN territory. Millions of cubic metres of water are used in each well fracking process (Campbell 2010), much of it sourced from surface waters, which can have effects on ecological integrity of river and lake systems. Lower water levels may impede travel up rivers during low flow periods, and can negatively affect the safety of frozen rivers during winter and spring for Aboriginal harvesters (Candler et al*.* 2010).

Water contamination

> *"A recent Congressional investigation revealed that, over a 4-year period, 14 leading gas companies used over 2500 hydrofracking products that contained 750 different chemicals, 29 of which were highly toxic or known carcinogens" — Entrekin et al. (2011, 508).*

Fracking requires introducing large amounts of chemicals into wells, as well as the flowback and management of large amounts of saline water. One study estimated that chemicals inputs are equal to 0.5 per cent of water inputs (Linley 2011), or approximately 150,000 litres of chemicals for a 30 million litre hydraulic fracturing job. Many of the chemicals used for fracking may be harmful to human health (e.g., benzene and arsenic, among many others[6]).

The "flowback" from injection sites, which may be stored in surface ponds or re-injected deep underground, contains highly saline waters and contaminants from fracking chemicals. They may be high in naturally occurring radioactive materials, arsenic, benzene and mercury (Campbell and Horne 2011). Studies have shown that wastewater from hydraulic fracturing must be re-injected into deep well aquifers or it will kill vegetation and degrade soil quality on land (Campbell and Horne 2011).

Entrekin et al*.* (2011) suggest that gas wells close to surface waters may impact those waters through elevated sediment runoff from pipelines and roads, altered streamflow from extraction, and contamination from introduced chemicals or resulting wastewater (including surfacing of deep groundwater brines), as well as spills of hydrocarbons. Forest loss is known to negatively effects water quality and runoff, reducing surface and groundwater quality.

Many studies have documented concerns with respect to groundwater contamination through casing failures and improper frac water disposal. According to de Rijke (2013, 14), "much of the fracking fluid remains underground (50 to 80 per cent in shale operations) and may pollute poorly understood water resources." Elevated levels of methane in groundwater, which may happen as some fracking fluids stay underground, is also a concern, as is the potential for naturally occurring radioactive material in produced water, which has been an

6 "Food grade" hydraulic fracturing additives are apparently available, but are not yet widely in use (Sample and Price 2011).

issue in U.S. shales (Linley 2011). Claims that the fracking fluids are far too deep to interact with much higher lying groundwater aquifers are only now being considered carefully, but the likelihood of this contaminated water resurfacing over the long-term remains poorly understood.

Fish and Fish Habitat

There are a number of ways that shale gas development can impact fish and fish habitat.

- Increased access for fishers into wilderness areas can have a major impact on competition for fish harvesting areas and increase pressures on stocks.
- Construction activities can increase the levels of total suspended solids (i.e., runoff of soil) in streams, which can negatively affect fish survival.
- The infrastructure itself—pipelines, transmission lines and service roads—can disturb streams and fish habitat through changes in stream cover and channel morphology. For example, the loss of vegetation in riparian areas may reduce stream shading and increase water temperature, which has a negative impact on some fish species.[7]
- Hydraulic fracturing water requirements can impact on fish habitat. Surface water withdrawals can reduce fish habitat. Lower water levels in streams can influence riparian ecological productivity and function, as can loss of vegetation and soil (e.g., erosion). For example, reduced in-stream flows have been connected to degradation of bull trout habitat (reported in Campbell and Horne 2011).
- Hydro-carbon spills making their way into a water body from the high amount of industrial activity and transport required in the gas sector can have severe detrimental effects on water quality and fish/aquatic habitat. Spills have the potential to directly destroy fish or contaminate them. Wu (2012) and Riverkeeper (2010) identify increased risks of fish kills from fracturing fluids spilling into wetlands and creeks.

Effects on Wetlands

The effects of water withdrawals on fens, bogs and other wetland formations, critical habitat features for wildlife in the northern boreal forest, may also be of concern. Changes to local hydrology due to compaction and runoff may have a significant impact on wetland habitat, and chemical spills have the potential to impact this habitat as well.

7 According to Levesque and Dube (2007), pipeline construction can cause relatively short but intense changes in water quality and other elements of aquatic ecosystem health, primarily at stream crossings and downstream in waterbodies. This includes increased turbidity in the water, removal of instream and riparian vegetation, physical stresses and mortality to fish, and destruction of fish habitat. There are increased risks of hydrocarbon spills during pipeline construction as well. Road building can also have similar effects on rivers and streams.

3.2.5 Effects on Human Health and Well-being

Potential shale gas development risks to human health and well-being include:

Accidents and malfunctions

> *"The Board [the NEB] has noticed an increased trend in the number and severity of incidents being reported by NEB-regulated companies in recent years" National Energy Board, in Hildebrandt (2013).*

There is a long list of potential accident and malfunction modes for the gas sector, some of the most common of which are corrosion and well failure (briny water is one contributing factor), and well failure due to seismic activity. Linley (2011) identifies spills of hydraulic fracturing additives and wastewater/produced water as commonplace occurrences. Radioactivity in drill cuttings, on-site disposal and landfill disposal are waste management issues that have raised in the U.S. (Sample and Price 2011).

Human health impacts

From a scientific perspective, the impacts of shale gas development on human health are still inadequately understood. Some analysts suggest that chemicals in flowback constitute human health hazards even in small amounts — possible effects include tissue damage, endocrine disruption, and elevated risks for certain cancers. For example, natural gas condensate may contain cancer causing chemicals (as reported in Environmental Law Centre 2013, 22). Leaks from gas wells may be an ever-present concern, and perceived risk of harvesting from areas affected by gas activities may also have adverse population health outcomes on First Nations heavily reliant on consumption of healthy country foods.

Social, economic and cultural impacts on First Nations people

The typical fly-in, fly-out workforce associated with oil and gas development brings social impacts to people living in the area. Population increases, particularly from transient workers, can further marginalize resident First Nations populations, both within communities and through increased competition for resources out on the land.

Impacts of shale gas activities on First Nations people can be widespread, due to strong cultural connections to the land. They may include the following:

- Increased land and water alienation;
- Increased risks and perceived risks of travel and occupancy of land and harvesting;
- Reduced country food harvesting and consumption, with associated impacts on food security;
- Reduced transmission of knowledge on the land;
- Reduced enjoyment of the land, for example due to noise and other sensory disturbances; and
- An inability to drink water from the land.

These impacts have also been detailed in a number of submissions related to gas development in northeastern B.C. (e.g., SFN and WMFN no date). They often have multiple gas industry-related factors driving them. For example, gas fields lead to increased traffic in previously "remote" (but often widely used by Aboriginal people) areas. This creates risks to traditional users and increases alienation from the land at the same time that sensory disturbance effects to wildlife and real and perceived concerns about contamination of water and wildlife add to cumulative Aboriginal alienation from lands and resources.

The increasing number of roads, pipeline ROWs and seismic lines all increase accessibility of recreational and harvester users of larger portions of First Nations' traditional territory. In addition, there are more people out working in camps who may choose to harvest fish and game when they are outside their work environment. More people on the land can impede the ability of aboriginal hunters and fishers to catch food by increasing competition for the same resource, disturbing wildlife from known harvesting locations, and increasing perceived risk of harvesting from the land for Aboriginal people, at the same time as reducing their harvesting practices and success rates (e.g., National Research Council 2003).

Psycho-social impacts may also occur (Health Canada 2005). These negative effects on mental and by extension, physical health, can stem from a number of stressors, including concerns about contamination of resources, the inherent conflict of personal economic needs versus the desire not to be involved in "destructive" industries, and the perceived loss of control over the future.

Overall, the loss of connection to the land, which results from concerns about contamination, fewer wildlife, and increased non-Aboriginal presence, has been shown to negatively impact Aboriginal communities on many levels. Hydro-carbon development has also been described as violating "the spirit of the land" and communal stewardship values central to First Nations' connection with country (e.g., National Research Council 2003).

3.2.6 Other Potential Impacts of Upstream Gas Sector-Related Activities

Increased seismic activity due to fracking

Scientists are still examining the potential for hydraulic fracturing to increase seismic activities from unconventional gas exploration/extraction activities (Sample and Price 2011; Linley 2011). The B.C. OGC (2012) found that fracking caused minor earthquakes in northeast BC in 2009 to 2011 and recommended further monitoring.

Long-term sustainability and the legacy of abandoned sites

According to the Environmental Law Centre (2013), B.C. taxpayers have already inherited approximately $650 million in liabilities for abandoned resource sector projects, "including many oil and gas sites."

3.3 EXISTING GAS SECTOR EFFECTS ON FNFN TERRITORY

"The shale gas fracking revolution has fragmented our landscape with over 80,000 km of seismic lines and thousands of km of roads and pipelines in less than a decade. Woodland caribou, beaver, other furbearers, moose, and fish abundance and health have all reportedly reduced in recent years. Our people rely extensively on moose and as the land is opened up to development there is increased competition from non-Aboriginal harvesters, and fear that industrialization is tainting our food." — some of the concerns raised by FNFN Chief Sharleen Gale at a Union of B.C. Indian Chiefs Meeting, November 27, 2013, in Vancouver.

This section first examines the amount of shale gas activity that has occurred in FNFN territory to date, and then profiles some of the effect encountered. While this study is not a full scope cumulative effects assessment — which would combine the total effects load of these past and present activities to those of reasonably foreseeable future development activities — examination of changes to date in the three FNFN shale gas basins helps to inform projections of potential future impacts in various LNG scenarios.

Data on linear and areal disturbance reported herein were developed in concert with FNFN Lands Department's GIS Technician, using B.C. OGC and other publicly available GIS data.

3.3.1 Spatial Footprint of Gas Activity in FNFN Territory

Looking at a map of oil and gas tenure in FNFN territory in 2002 reveals a largely blank slate. Figure 5 shows small patches south of Maxhamish Lake in the Liard Basin and in the southeastern portion of the Horn River Basin tenured for conventional oil and gas activities. Only the north and west portion of the Cordova Embayment was subject to substantial tenure by oil and gas companies.

Much has changed in the interim. As shown in Figure 6, between 2002 and 2012 an additional 12,600 km^2 of the three shale gas basins was tenured out to gas companies. By 2012, one-fifth of the total area of the Liard Basin, almost half of the Cordova Embayment, and nearly two-thirds of the Horn River Basin was subject to gas tenure. The majority of this tenure letting came from 2008 onwards as the economic potential of the shale deposits beneath FNFN territory became readily apparent.

This expansion was part of an overall B.C. natural gas sector boom during the past decade. As shown in the "before and after" images of the years 2006 and 2013 in Figure 2 of the Phase 1 report, industrial development within FNFN core territory has accelerated rapidly in the last decade with the rise of shale gas basin exploration and development. Hydraulic fracturing to extract gas from the Horn River Basin has been the major driver of the expansion.

Between 2007 and 2012, 307 well pads were developed and 627 wells drilled in the three shale 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 3 of 88 wells in 2005/6.

Figure 5: Oil and Gas Tenure in the Three FNFN Shale Basins in 2002

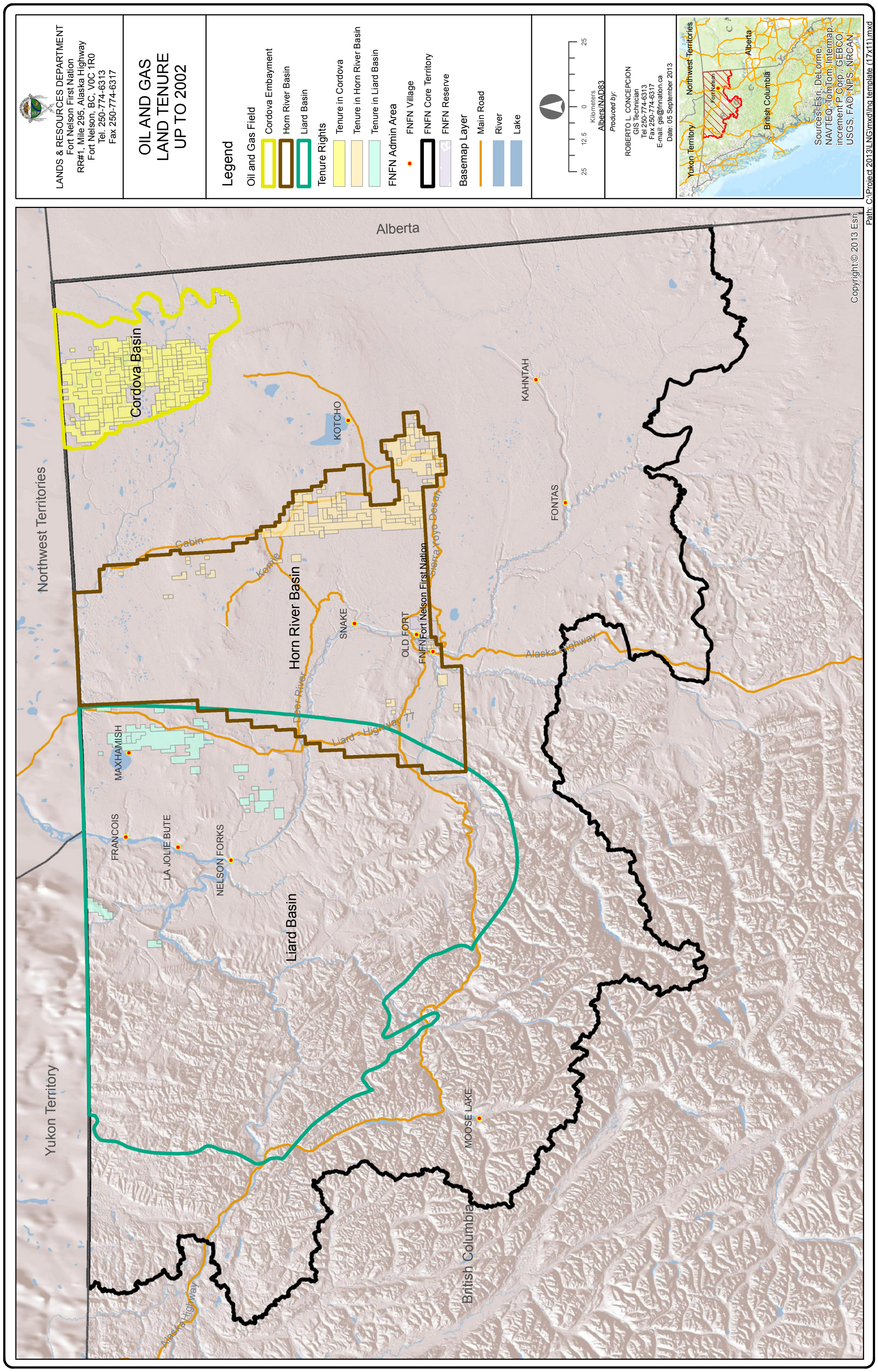
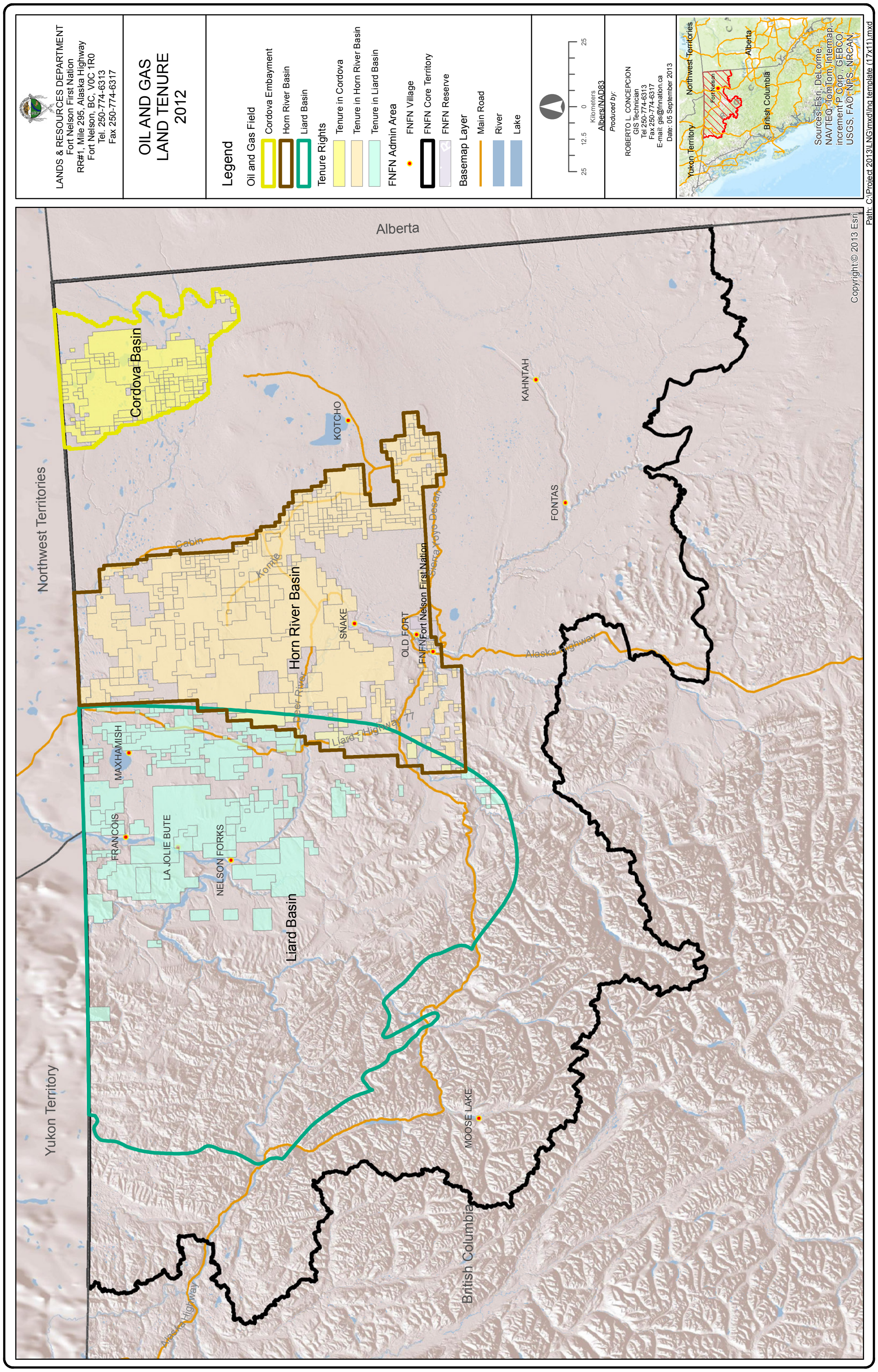


Figure 6: Oil and Gas Tenure in the Three FNFN Shale Basins in 2012



Amount of linear disturbance

Linear disturbances (roads, seismic lines and pipeline ROWs) have increased dramatically over the last decade. As shown in Figures 5 and 6 below, the amount of gas sector roads and total linear disturbance in FNFN territory has grown rapidly over the past half-decade.

Using B.C. OGC data, the author calculated that the total amount of linear disturbance added to the three shale gas basins in FNFN territory[8] as a direct result of gas sector activities between 2002 and 2012 was some 78,583 km, or over 2.1 km/km^2 of added disturbance in the combined 36,700 km^2 of these shale gas basins. This includes over 5,200 km of permitted new roads between 2007 and 2012 alone (Figure 7), an estimated 2290 km of pipelines,[9] and large amounts of seismic line clearing.

The majority of this linear disturbance has been in the Horn River Basin and Cordova Embayment, respectively. By 2012, total linear disturbance had grown to an average of 6.84 km/km^2 in tenured portions of the Horn River Basin, 5.93 km/km^2 in the Cordova Embayment, and 1.07 km/km^2 in the Liard Basin.[10] These numbers are not academic. As noted above, levels of landscape fragmentation much lower than the numbers already present in the Horn River Basin and Cordova Embayment have been shown to have detrimental effects on woodland caribou and other species.

FNFN Lands Department has identified a variety of concerns related to these linear disturbances (Lowe 2014), including but not limited to:

- Observed woodland caribou and moose population decline;
- Increasing wolf populations;
- Diversion, erosion and other effects on fish bearing streams and riparian ecosystems;
- Reduced sense of safety and welcome for First Nations harvesters with road checks, speeding industry vehicles, and high traffic; and
- Loss of access to hunting areas and/or increased competition with non-First Nations recreational users and harvesters (effects caused by roads themselves plus regulations regarding firearms near development).

Areal Disturbance

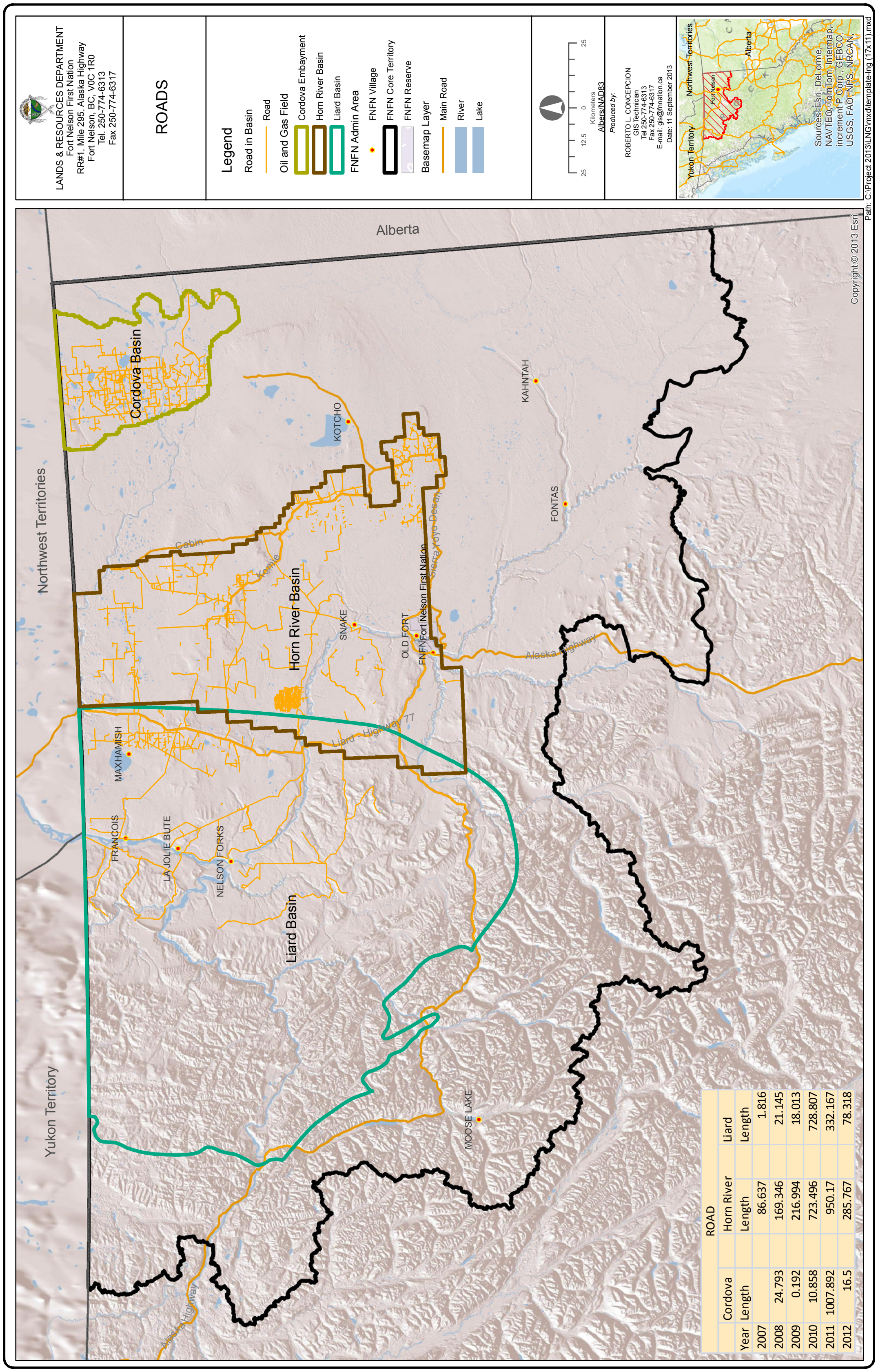
Another measure of disturbance and fragmentation is the amount of areal disturbance in FNFN territory.

8 While gas activities also occur outside of the three shale gas basins in FNFN territory, this study has pinned its GIS data analysis only to within the three basins.

9 Pipeline data has until recently been spatially characterized using an area rather than linear metric, making estimation of the exact length of pipeline difficult. According to FNFN Lands Department calculations using B.C. OGC data, the following pipeline ROW effects occurred within the three basins between 2002 and 2012: 1. Cordova Embayment — 12.81 km^2; 2. Horn River Basin — 31.32 km^2; and 3. Liard Basin — 13.27 km^2. Using an estimate that the average pipeline ROW is 25 metres, this equates to some 2290 km of pipeline.

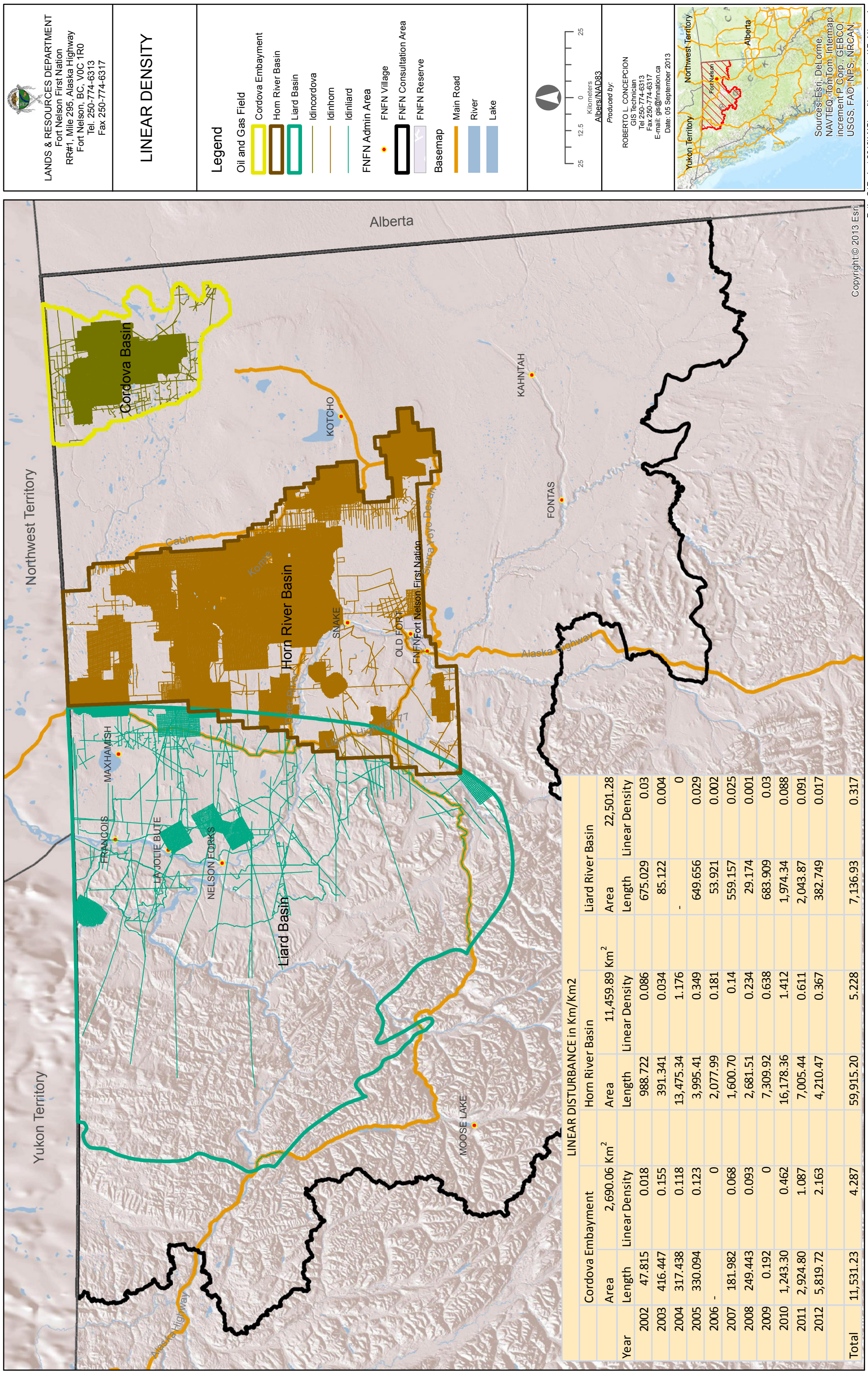
10 This drops to 5.23 km/km^2, 4.29 km/km^2 and 0.32 km/km^2, respectively, when non-tenured portions of the three shale basins are included. The Liard Basin, in particular, has remained less impacted, although a surge from 2010 forward in the highly prospective area on the east side of the Liard River in this basin has seen extensive growth in activity levels (Apache Corporation 2012).

Figure 7: New Gas Sector Roads in FNFN Territory, 2007 to 2012



	Cordova	ROAD Horn River	Liard
Year	Length	Length	Length
2007		86.637	1.816
2008	24.793	169.346	21.145
2009	0.192	216.994	18.013
2010	10.858	723.496	728.807
2011	1007.892	950.17	332.167
2012	16.5	285.767	78.318

Figure 8: Linear Disturbance in FNFN Territory as of 2012



LINEAR DISTURBANCE in Km/Km2

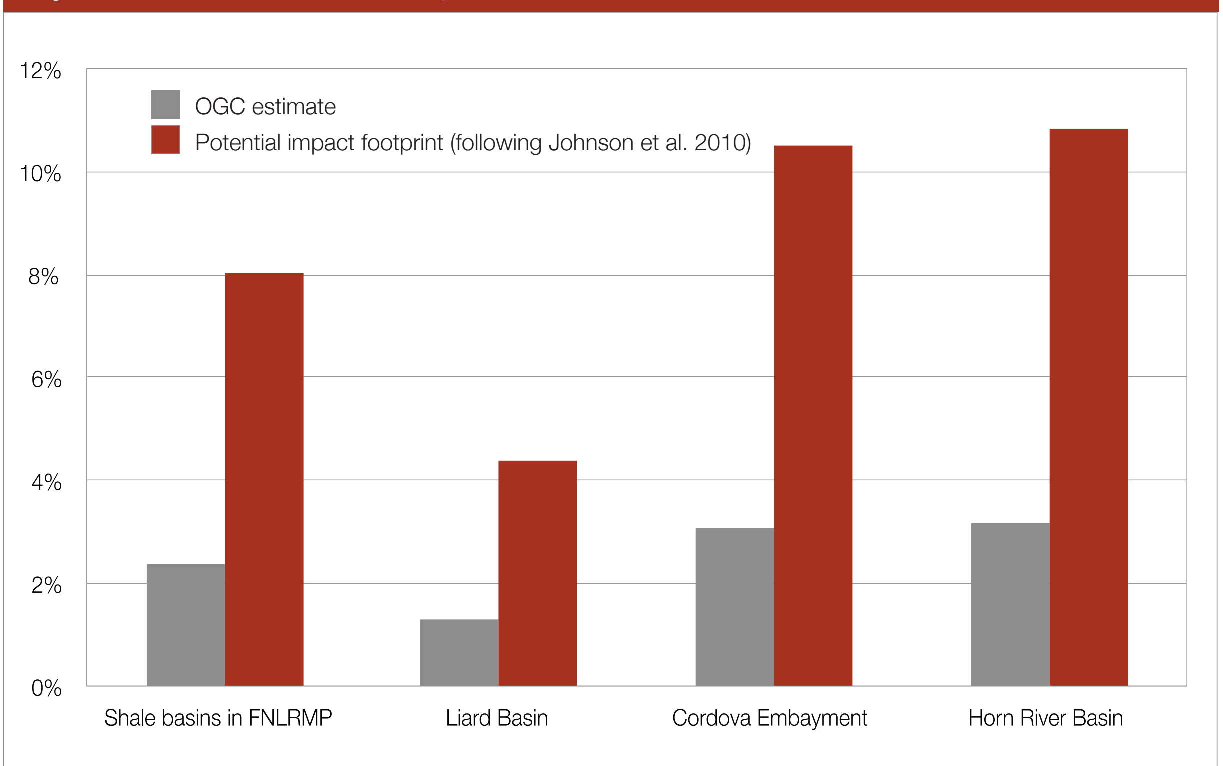
	Cordova Embayment		Horn River Basin		Liard River Basin	
	Area	2,690.06 Km^2	Area	11,459.89 Km^2	Area	22,501.28
Year	Length	Linear Density	Length	Linear Density	Length	Linear Density
2002	47.815	0.018	988.722	0.086	675.029	0.03
2003	416.447	0.155	391.341	0.034	85.122	0.004
2004	317.438	0.118	13,475.34	1.176	-	0
2005	330.094	0.123	3,995.41	0.349	649.656	0.029
2006	-	0	2,077.99	0.181	53.921	0.002
2007	181.982	0.068	1,600.70	0.14	559.157	0.025
2008	249.443	0.093	2,681.51	0.234	29.174	0.001
2009	0.192	0	7,309.92	0.638	683.909	0.03
2010	1,243.30	0.462	16,178.36	1.412	1,974.34	0.088
2011	2,924.80	1.087	7,005.44	0.611	2,043.87	0.091
2012	5,819.72	2.163	4,210.47	0.367	382.749	0.017
Total	11,531.23	4.287	59,915.20	5.228	7,136.93	0.317

Areal disturbances (e.g., forest clearing for facilities, gas plants, and well pads) have increased dramatically over the last decade. Areal disturbance can be measured by physical footprint or by impact footprint, the latter also known as Zone of Influence (ZOI). The B.C. government has generally chosen the former when characterizing change in FNFN territory. B.C. OGC (2013c) suggests that as of 2012, 148,728 hectares of the portion of the Fort Nelson Land and Resource Management Plan (FNLRMP) covered by the three shale basins, or 2.36 per cent, has been "used" for oil and gas activities. The amounts per basin are 1.28 per cent for Liard, 3.08 per cent for Cordova, and 3.18 per cent for Horn River (B.C. OGC 2013c). It is also worth noting that only three years ago, the B.C. OGC (2010, 5) estimated that "the total oil and gas disturbance represents less than one per cent of the entire HRB [Horn River Basin] area." This suggests a more than tripling of the total disturbed area in the Horn River Basin between 2009/10 and the end of 2012.

It is also worthy of note that the B.C. OGC's data refers to surface footprint only and may well not reflect the "impact footprint" or "zone of influence" (ZOI) of these activities on FNFN land and waters. Impacts are felt well beyond the physical limitation of the immediate change in a ZOI. For example, Johnson et al. (2010), in discussion of the effects of shale gas development in the U.S. Northeast, predicted that for every acre of direct disturbance, there are 2.41 more acres subject to "edge effects" (see "Reduction in forested landscapes" in Section 3.2.2). If this is the case in FNFN territory, the amount of areas used in FNFN territory impacted from oil and gas activities grows from 148,729 hectares to over 500,000 hectares. The expanded impact footprint in this scenario for the three shale gas basins is shown in Figure 9 alongside the B.C. OGC (2013c) physical footprint calculation.

Identification of a ZOI or total impact footprint provides a more realistic portrait of areal disturbance effects. By this measure, some 8 per cent of the FNLRMP and over 10 per cent of each of the Horn River Basin and Cordova Embayment had likely been impacted by oil and gas activities by the end of 2012.

Figure 9: FNFN Land Base "Used by Oil and Gas Activities" as of 2012



The author also looked at a measure of areal disturbance important for wildlife by using a 500 metre buffer zone around all linear and areal disturbances (250 metres on either side of the centre line of the physical bounds of disturbance). A 500 metre zone has been recommended by wildlife biologists for characterization of disturbance/fragmentation of woodland caribou habitat (Environment Canada 2011). This measure of buffered areal disturbance found that as of the end of 2012, 71 per cent of the Horn River Basin, 73 per cent of the Cordova Embayment, and 33 per cent of the Liard Basin's tenured areas have been subject to buffered areal disturbance from gas sector activities.[11] This amounts to more than 8500 km^2 — or 850,000 hectares — of core FNFN territory being subject to areal disturbance from gas sector activities to date.

3.3.2 Example Effects of Changes to Date on FNFN Territory

Unless otherwise noted, all statistical data referred to below was generated by FNFN Land Department's GIS Technician using data from online accessible by B.C. OGC.

Wildlife Effects

> *"In north eastern B.C., over 75% of boreal caribou range is already tenured and being developed for petroleum and natural gas. This level of activity is reported to exceed a disturbance threshold in 12 of 15 Core Habitat areas, a point at which "caribou populations achieve negative population growth" — Environmental Law Centre 2013, 24.*

Woodland caribou are in some ways the "canary in the coal mine," an early warning system for ecological change in FNFN territory, because this species requires large areas of undisturbed habitat to thrive and are thus vulnerable to industrial fragmentation and disturbance effects.

A large portion of the tenured lands in the three shale gas basins in FNFN territory is also core woodland caribou habitat, areas the species relies upon for herd survival. For example, 100 per cent of the portion of the Tsea Core in the Horn River Basin is tenured to gas company interests, as is 98 per cent of the Kiwigana Core and 92 per cent of the Fortune Core.[12] That alone is cause for concern, but more important is what is actually happening in these areas in terms of industrial effects. Figure 10 (following FNFN 2013) identifies portions of those core caribou habitats where linear disturbance has already exceeded recognized thresholds of manageable change for woodland caribou. Large portions of the Fortune, Paradise and Kiwigana Cores, and all of Shush Creek and Tsea Cores have entered a critical risk zone, beyond 2.0 km/km^2, at which herd populations may decline and extirpation — loss of all animals of a species from a certain area — becomes a possibility (the red areas in Figure 10).

FNFN members have also raised concerns about effects on multiple other species in recent years, including population and health status decline of moose — due to a variety of causal factors such as increased access for hunters, water and air contamination, and habitat fragmentation — and beaver — with particular concerns about water quality and quantity effects of gas activities (FNFN 2012a; Lowe 2014). Increased gas sector activity leads to habitat fragmentation, increased predation risk, and increased access into the area for non-Aboriginal harvesters, among other effects on wildlife population and health.

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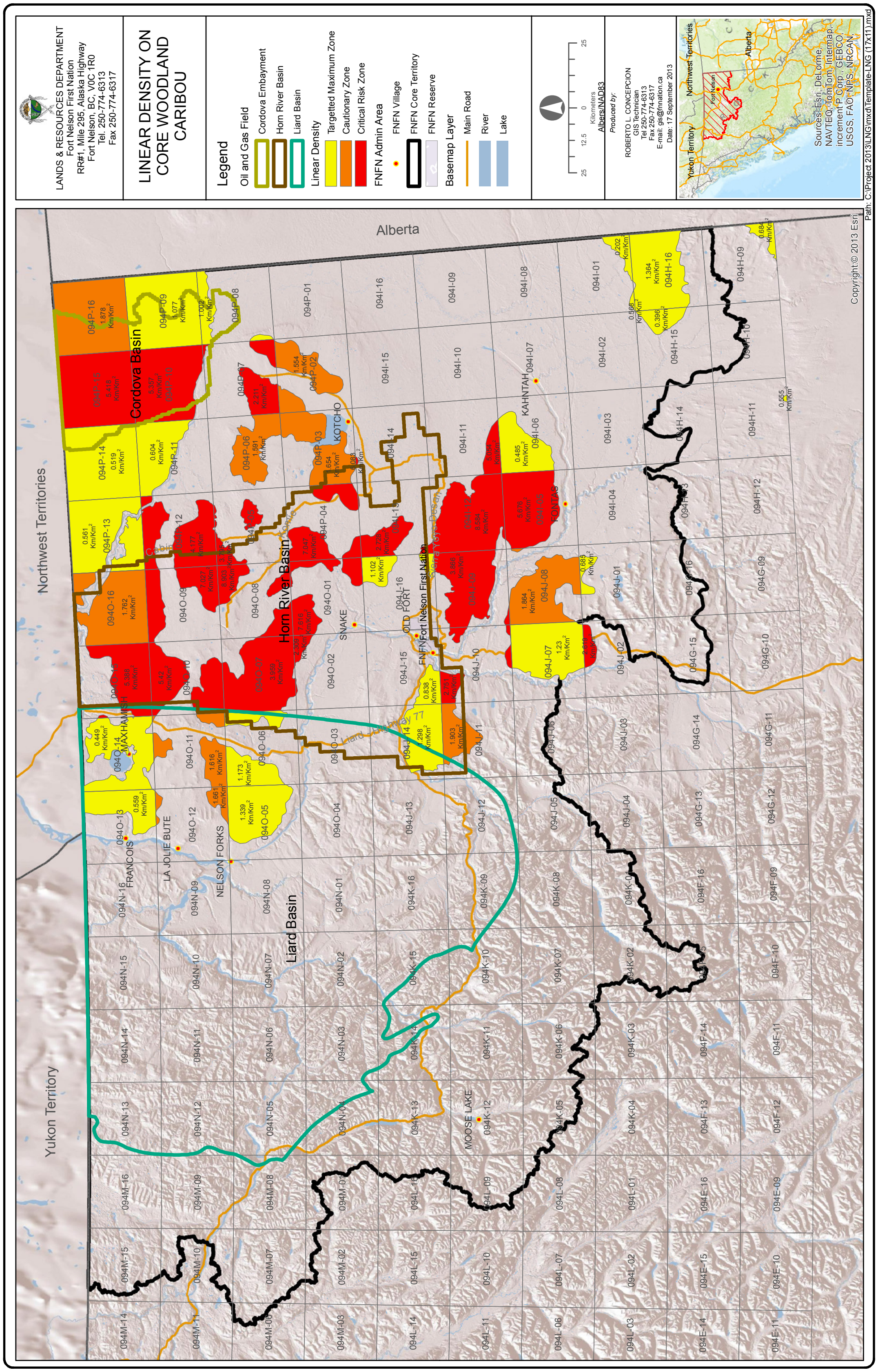
11 These numbers drop to 59 per cent, 54 per cent and 12 per cent, respectively, when non-tenured portions of the three basins are included, based on B.C. OGC spatial data.

12 Overall, some 92 per cent of the Cordova Embayment, 41 per cent of the Horn River Basin, and 9 per cent of the Liard Basin is core woodland caribou habitat.

Figure 10: Linear Disturbance Density on Core Woodland Caribou Habitat in FNFN Shale Basins



Water Effects

Hydraulic fracturing requires large volumes of water, creating stress on fresh water systems and increasing the amount of contaminated water on the surface and in underground deep disposal sites, potentially altering area hydrogeology.

Already high fracking water demand is taken to the extreme in the case in FNFN territory. As noted by Redden (2012, 70), "perhaps the biggest issue confronting Horn River and Montney operators is the exorbitant demand for water." 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 10 and 15 times the amount used in Montney. As a result, water withdrawals from FNFN territory have also increased rapidly, both in amounts and sources, over the last decade.

Air Quality and GHG Emissions Effects

A full calculation of the contribution of FNFN territorial gas sector activities to local and regional air quality and GHG emissions is beyond the scope of this Project. What is known is that:

- FNFN members report localized air quality concerns around gas plants, compressor stations, wells sites and other gas sector physical works and activities (e.g., FNFN 2012b).
- Gas sector activities are already the major contributor in the region to B.C.'s GHG emissions, even though the sector is relatively "immature" and thus subject to likely future high growth in production and related GHG emissions.
- Gas plants and compressors stations are the region's largest point sources for gas.
- Provincial EA's for the Cabin Gas Plant and the Fortune Creek Gas Plant found that both projects are likely to have significant adverse effects on GHG emissions at the provincial level. Regardless, both were approved as proposed without additional required GHG emissions reductions terms or conditions.
- Carbon dioxide (CO_2) is and will likely remain the most prominent GHG emissions type related to gas sector activity in FNFN territory. Formation CO_2 in FNFN shales is very high; Horn River Basin in particular at 12 per cent, but Liard and Cordova are both higher than average as well at around 7-8 per cent $C0_2$. This is well above WCSB averages.

Summary of Key Elements of Changes to Date

Data available using public sources indicates the following serious issues with existing gas development in this still "immature" (i.e., yet to reach its production peak) region:

- Increased habitat fragmentation, including extremely high linear disturbance in core woodland caribou (a species at risk) habitat and indeed throughout the Horn River Basin and Cordova Embayment;[13]
- Almost 80,000 km of permitted linear disturbance over the past decade;
- Over 2000 km of road in the Horn River Basin and over 1,000 km in each of the Liard Basin and Cordova Embayment. In addition, over 2290 km of pipeline has created new linear disturbance in FNFN territory;
- Overall, areal disturbance of over 8500 km^2, when buffered by 250 metres on either side of the physical industry footprint, within the portion of FNFN territory subject to tenure in the three shale basins being studied herein;
- Total water withdrawals in FNFN have grown exponentially over the past decade; and
- Both local air quality effects and the gas sector's contribution from FNFN territory to provincial GHG emissions have grown significantly.

13 FNFN is not alone in these concerns. The B.C. Ministry of Environment and Environmental Canada are well aware of threshold exceedences and extirpation threats in most of northeast B.C.'s woodland caribou Core Habitat, as reported on pg. 24 of Environmental Law Centre (2013, 24).

SECTION 4

Establishing LNG-Induced Physical Work Requirements

4.1 INTRODUCTION

This section provides a range of estimates of the amount of physical works and activities required to support LNG-induced gas extraction within shale gas basins in FNFN territory over the estimated first 20 years of a B.C. LNG export sector.

This section of the report provides a range of estimates of the amount of physical works and activities required to support LNG-induced gas extraction within shale gas basins in FNFN territory over the period 2018–2038, the estimated first 20 years of a B.C. LNG export sector.

The first focus is to identify the numbers of wells and well pads required to satiate LNG-induced gas extraction requirements. These metrics are used because they are the critical drivers of upstream gas activities, from which estimates can be made on a per-unit basis of what levels of other types of supporting physical works and activities are required.

The report then identifies what additional supporting physical works and activities will be required in these different well/well pad scenarios, using a mixture of experience in FNFN territory during the shale gas era to date (from 2006–2013) and proxy studies from other gas producing regions.

The estimates of all physical works and activities together are then used in Section 5 to calculate the range of possible environmental effects on FNFN territory of this LNG-induced gas extraction.

4.2 ESTIMATING THE NUMBER OF WELLS AND WELL PADS REQUIRED

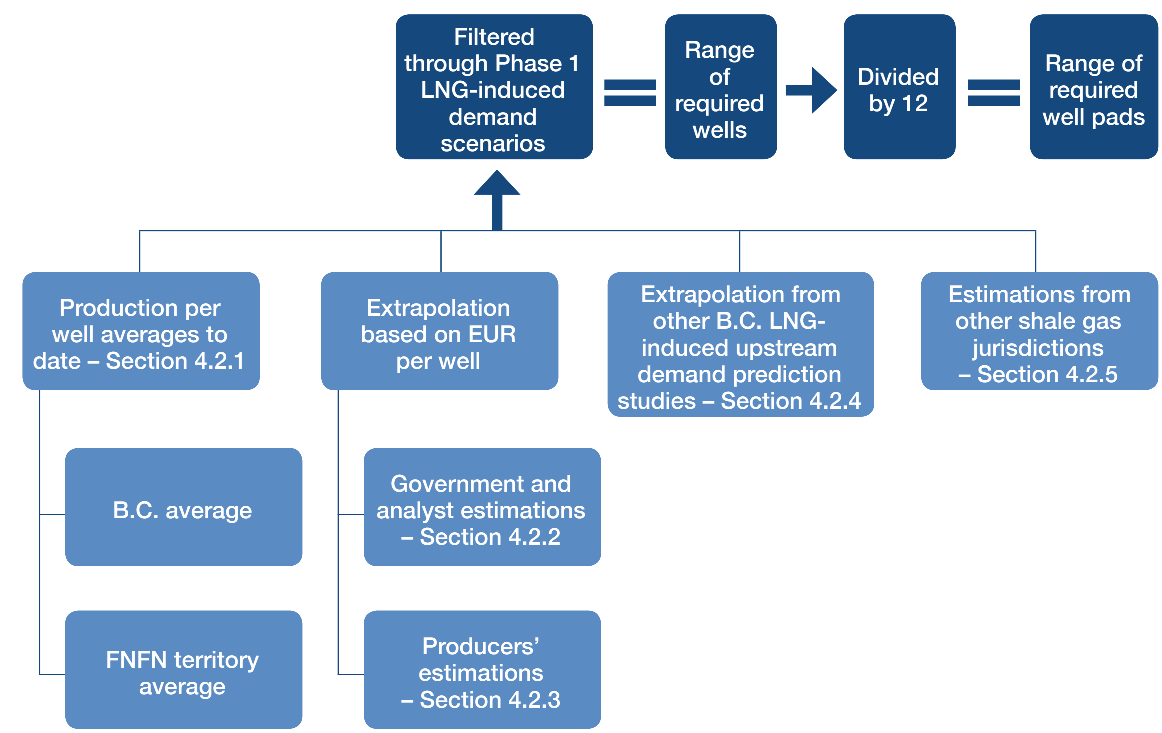
Figure 11 shows the key types of inputs focused on in the search for a range of the number of wells required in FNFN territory to support LNG-induced gas extraction. For each triangulation tool, a brief description is provided and then the applicable well count projections for FNFN territory are identified, along with strengths and weaknesses of the approach. In addition, as shown in Table 5 in section 4.2.6, a confidence rating of the applicability of each estimate to the FNFN LNG-induced gas extraction question is provided.

Gas well decline rate

> *"[In B.C., unconventional well production drops much faster than conventional] meaning that a drilling treadmill is required just to keep production flat, let alone grow it" — Hughes (2014, cited in Gillis (2014)*

A critical consideration in estimating the number of wells required to produce a certain amount of gas is the decline rate of gas wells. When a new well is drilled, it penetrates a rock unit with abundant gas, and there tends to be high pressure, which yields gas at a very high initial production (IP) rate. There is a typical decline curve for a horizontal well that sees a rapid drop in production after the first year. Mason (2011, 2) suggests that "horizontal shale gas wells produce approximately 25 per cent of their EUR in the first year." Over time, as gas leaves the underground formation, pressure also reduces and flow rates reduce, often dramatically. Eventually the well will yield so little gas that it will become uneconomic to operate and will be abandoned. This decline rate means that additional replacement wells continuously need to be drilled to keep production rates at the same level. A high decline rate such as that found in the Horn River Basin (Hughes 2014 suggests the field decline rate for Horn River is demonstrably higher than the province as a whole with average 3 year well drop off at 80 per cent vs. 69 per cent) means that this well replacement process needs to be accelerated.

Figure 11: Inputs Used to Estimate Wells/Pads Required in FNFN Territory



4.2.1 Current B.C. and FNFN Territory Average Production per Well

B.C. Average

An extremely simplistic triangulation tool is to use the current average production rate per well at the broader B.C. level. Hughes (2014) notes that as of September 2013 more than 25,000 wells had been drilled, of which 9,080 were actively producing gas. This equates to an average of 0.44 Mmcf/day per currently producing well, given estimates of approximately 4.0 Bcf/day of raw gas production in B.C. Extrapolating, this would require 1,112 wells to produce 0.49 Bcf/day and 6,084 wells to produce 2.68 Bcf/day, the amounts required as per LNG-induced gas extraction estimates for FNFN territory from the Phase 1 study, if FNFN wells were expected to produce at the current B.C. average per well.

The comparative utility of this triangulation tool is very low. The production rates estimated include both conventional and unconventional wells, and include wells at all stages of their productive lives. Thus, the production rate average is very low in comparison to those likely from future new shale gas wells in FNFN territory, which would likely substantially reduce the number of expected wells. In addition, this method includes no calculation of replacement wells, a fact that would see a shift in the other direction to the need for more wells over the 20 year period.

Current FNFN Shale Gas Well Production Average

According to data collected by the FNFN Lands Department using B.C. OGC shape file database information, between 2006 and 2013, 892 gas wells were drilled in the areas underlain by the three FNFN shale basins. At their peak production to date, in 2011, they produced 400 MMcf/day, or at an average rate of 0.45 Mmcf/day per well. While this is very close to the B.C. average of 0.44 Mmcf/day, this is much lower than would be expected for a new gas field, especially in an area with such high gas flow rate potential as the FNFN shales. This is a clear indication that many of the wells drilled in the area underlain by FNFN shale basins to date are not currently producing or not producing to their maximum potential. Thus, extrapolating the number of required wells to produce 0.49 Bcf/day to 2.68 Bcf/day using this metric — the amount of wells, excluding replacement well requirements, would be between 1089 and 5956 — must be treated with very low confidence.

Slightly higher confidence may be found in estimating the current production average using only the wells drilled targeting shale deposits in the three basins. Indications are that, especially in the early years after 2006, some of the wells drilled targeted conventional deposits. If it is assumed that approximately 400 wells were drilled for shale targets between 2006 and 2013 and that they are producing a maximum of 300 Mmcf/day to date, this equates to a slightly higher 0.75 Mmcf/day per well, and the need for between 653 and 3573 wells.

Nonetheless, overall it is safe to say that there appears to be little value to extrapolating future well requirements in FNFN territory using current average extrapolation rates from FNFN territory or the B.C. average. In other words, the future in FNFN territory is likely to be very different from the present, especially given strong EUR values in FNFN shales (see Section 4.2.2).

4.2.2 Extrapolating from Government and Analyst EUR Predictions

One triangulation method used to estimate the required number of wells was a direct division of the total required gas over 20 years from FNFN territory to fuel the LNG sector against the expected ultimate recovery (EUR) per well in FNFN shale basins. Given evidence available from secondary sources, the author adopted the following estimates of average EUR per well:

- Cordova Embayment: 4–8 Bcf
- Horn River Basin: 9–12 Bcf
- Liard Basin: 12–15 Bcf (Apache Corporation (2012) outlier at 18 bcf)[14]

Given that the amount of future LNG-induced extraction from each FNFN territory shale basin is unknown, it was necessary to estimate an average FNFN shale basin EUR per well. Taking a median EUR estimate for each of the basins (six, 10.5 and 13.5 Bcf/well respectively), the average EUR if all were developed equally equates to 10 Bcf/well. This number is much higher than historic B.C. well EURs.

Table 2 shows the calculation of required wells to support LNG-induced gas extraction, on a per-basin and FNFN average basis.

Table 2: Extrapolating from EUR per Well Data, by FNFN Shale Basin

FNFN Shale Gas Basin	EUR per well	Required wells to support LNG-induced demand	
		Low — 3.56 Tcf over 20 years	High — 19.5 Tcf over 20 years
Horn River Basin	10.5 Bcf	347	1,896
Liard Basin	13.5 Bcf	267	1,462
Cordova Embayment	6 Bcf	593	3,250
FNFN shale gas basin average	10 Bcf	356	1,950

Based on this EUR per well data, somewhere between 267 and 3250 wells would be required to fuel LNG-induced gas extraction. The author's chosen average Bcf/well metric of 10 Bcf/well, which is conservatively much higher than industry average to date and much higher than Montney averages, would see between 356 and 1950 new wells required to produce the required gas.

There are fundamental limitations to the applicability of this method. For one thing, it is difficult to estimate with certainty beforehand the accuracy of EUR per well metrics, especially in an immature basin. Secondly, it remains uncertain how much gas each of the three FNFN unconventional basins will contribute to the LNG production system. Since they have different EUR per well, this is a cause of uncertainty. Most critically, this calculation does not consider the role of replacement wells to maintain required levels of production, which would be ongoing up to and likely after the 20 year mark. Confidence in this metric is therefore by itself low.

14 Sources of EUR ranges for all three shale basins include B.C. OGC (2013b); Walden and Walden (2012); KM LNG (2010); Hughes (2014); and others identified in Table 7 of the Phase 1 report for this study.

4.2.3 Extrapolating from Producers' Estimates/Modeling

In 2012, Apache Corporation identified a "Liard Basin Development Model" for its highly promising play north-west of Fort Nelson and results of early drilling. In it, Apache suggested the following:

- EUR per 18 frac well of 74 Bcf of raw gas, which equates to over 800 Bcf EUR per well pad in its 12 wells per pad model; and
- 54 Tcf of raw gas recovery from 731 wells on 61 well pads over an unknown period of time.

If in fact this Liard Basin Development Model played out as suggested by Apache, the amount of wells and well pads required to satiate LNG-induced gas requirements from FNFN territory would be lower than otherwise expected. At the most optimistic, as few as between 50 and 265 wells could produce the required gas.

These well returns would be exponentially higher than average returns to date in FNFN territory, in the B.C. gas industry, or indeed anywhere in North America. They should also be treated with high caution given the extremely small sample size used to develop the model. Confidence in this triangulation tool is very low.

Apache Corporation focused on its Horn River Basin holdings in providing corporate supply pool data for the proposed Kitimat LNG facility (KM LNG 2010). The proponent estimated it would need to drill 1,018 wells between 2010 and 2030 to average 553 Mmcf/day of production over that time period. This equates to between 902 and 4,932 wells in the FNFN LNG-induced gas extraction scenario over a similar 20 year time period (2018-2038).[15] However, this amount needs to be reduced by 19 per cent because Apache assumed in its modeling that amount of process "shrinkage" into the number of wells required, whereas this study conservatively does not. At a reduction of 19 per cent, extrapolation from the Apache Horn River Basin model estimates between 731 and 3,995 wells in the FNFN LNG-induced gas extraction scenarios.

This Horn River Basin modeling seems a more supportable estimate than the Liard Basin Development Model. Even though the estimated 12 Bcf EUR is higher than industry averages, it may well accurately reflect a realistic future for the gas rich Horn River Basin and is close to the estimated EUR per well (10 Bcf) adopted in this study. This triangulation tool also benefits from including replacement well estimates. As a result, it is the proxy study the author has the highest confidence in adopting as a realistic forward-looking estimate of well needs.

4.2.4 Extrapolation from Other B.C. LNG Upstream Demand Prediction Studies

National Bank (2013)

Estimates of future upstream gas sector 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 or more have been proposed to date) could see 6,500 new wells drilled in the Western Canada Sedimentary Basin (WCSB) to provide gas feedstock to these facilities. Using the simplest possible formula, 10 to 25 per cent of those new wells attributable to FNFN territory would account for 650 to 1,625 wells.

15 This was calculated by the following formula: (0.49/0553 (FNFN Low Growth LNG Demand Scenario Mmcf/day divided by KM LNG Horn River Mmcf/day production estimate), multiplied by 1018 wells) = 902 wells; with a similar calculation for the FNFN High growth LNG Demand Scenario of 2.68 Bcf/day.

Limitations of this triangulation tool are that it does not necessarily account for decline rates. In addition, it is unclear what EUR/well and other metrics were used in the National Bank calculations. Thus, confidence in its accuracy in relation to FNFN well requirements is very low.

Hughes (2014) — Method 1 (Average Wells per Year Extrapolation)

In *BC LNG: A Reality* Check, Hughes (2014, 4) estimates that the production of 14.6 Bcf/day to fuel B.C. LNG exports, the amount currently approved for export by the National Energy Board (NEB):

> *"would require drilling 50,000 new wells in the next 27 years (double the approximately 25,000 wells drilled in BC since the 1950s). Given the steep production declines associated with shale- and tight-gas, drilling rates of more than 3,000 new wells per year would be required to ramp up production to required export levels, followed by nearly 2000 wells per year to maintain production."*[16]

The Hughes study identifies an average of 1852 wells per year that will be developed between 2014 and 2040, in order to produce an average of 14 Bcf/day. Dividing the Hughes average daily production by the range of LNG-induced extraction values from FNFN territory (0.49 to 2.68 Bcf/day) comes up with the following:

Table 3: Extrapolating from Hughes (2014) — Method 1: Average Wells per Year

FNFN LNG-induced Demand Supply Rate	FNFN Proportion of Total Gas Production Required to Support LNG (14 Bcf/d)	Number of FNFN Shale Wells per Year Required to Support LNG (total wells = 1852)
0.49 bcf/day	3.5 per cent	65 new wells per year (1,852 x 0.035)
2.68 bcf/day	19.1 per cent	354 new wells per year (1,852 x 0.191)

Over the 20 years for which this study has developed the FNFN gas demand scenarios, this equates to between 1,296 and 7,089 new wells in FNFN territory to fuel LNG demand levels.

However, adjustments are necessary to this metric, given fundamental differences between FNFN territory shale gas fields and the B.C. averages uses by Hughes. In his calculations, Hughes (2014, 19 — endnote 8) assumes that there will be one year field decline rates of 26 per cent per year, the current B.C. average. This is conservative and likely underestimates the number of wells required in FNFN territory, given more one year field rapid decline rates for Horn River of 37 per cent.

Hughes also assumes average first year production rates of 2.44 Mmcf/day of raw gas per well, again the B.C. average. In this instance Hughes' metric leads to a likely overestimate of the numbers of wells required, given FNFN territory's higher EUR per well than the B.C. average. In order to overcome this likely overestimate of the number of wells required, the author did the following re-calculation. Hughes (2014) estimated B.C. average of 2.44 Mmcf/day first year production rates comes to 890.6 Mmcf/year. Using Mason's (2011) estimate that 25 per cent of total well production is from the first year, this equates to a 3.56 Bcf EUR/well. The author moved

16 Hughes suggests that this activity, in addition to other impacts, would require water consumption exceeding that of the City of Calgary.

this up to 4.16 Bcf EUR/well to compensate for FNFN's faster decline rate and divided this by this study's assumption of 10 Bcf EUR/well in FNFN territory. The author then reduced the number of wells estimated for FNFN territory accordingly to:

- Low LNG-Induced Growth = 1,296 * 0.416 = 539 wells required in FNFN territory
- High LNG-Induced Growth = 7,089 * 0.416 = 2,949 wells required in FNFN territory

Thus, it is estimated using this first triangulation tool from Hughes (2014) that between 539 and 2949 wells would be required in FNFN territory over the first 20 years of LNG-induced gas extraction.

While strengths of this triangulation tool include the explicit use of replacement wells in the analysis, there are some limitations to its utility as well. Perhaps most importantly, well counts in this instance include wells required to maintain domestic supply, which are not included in this FNFN LNG Demand study. This limitation reduces confidence in this triangulation tool.

Hughes (2014) Method 2: Visual Approximation from Tabular Information

In light of the above-noted limitation re: inclusion of domestic supply wells in Hughes (2014), the author calculated a second extrapolation method from the same study. Figure 6 in Hughes (2014) was reviewed visually (supporting data tables were not available in the published work) to calculate the total number of wells required between 2018 and 2038 attributable only to LNG-induced growth scenarios, and an initial range of FNFN well numbers in same, as follows:

- 4.9 Bcf/day LNG-induced demand = approximately 11,500 wells between 2018 and 2038, of which between 1150 and 2875 would be in FNFN territory — 10 to 25 per cent)
- 10.7 Bcf/day LNG-induced demand = approximately 26,000 wells between 2018 to 2038, of which between 2600 and 6500 would be in FNFN territory)

However, again given that this estimate was based on wells that have lower EUR, adjustments were also necessary to this second triangulation tool. Thus, the following calculations were conducted:

- Low LNG-Induced Growth = 1150/2875 * 0.416 = between 478 and 1,196 wells required in FNFN territory
- High LNG-Induced Growth = 2600/6500 * 0.416 = between 1,082 and 2,704 wells required in FNFN territory

Thus, this second triangulation tool from Hughes (2014) estimates that between 478 and 2704 wells would be required in FNFN territory over the first 20 years of LNG-induced gas extraction.

While this method benefits from focusing solely on LNG-induced gas extraction, there are also some limitations. In particular, this was a visual analysis of graphed data only, so there might be slight inaccuracies in the estimate drawn from the Hughes report. Overall, however, the second metric is held in slightly higher confidence than the first, because domestic supply wells are removed.

Perhaps the greatest benefit of the Hughes study is its credible analysis of natural gas production dynamics. The modeling reflects the importance of continual drilling of a large number of replacement wells to offset well and field declines in ways that some of the other estimates used herein do not. According to Hughes, B.C. hydraulic fracturing wells have rapid diminishment curves, with as much as 80 per cent declines in the first three years of production for Horn River (versus 61 per cent for Montney and a 69 per cent B.C. average).[17] This means that in order to maintain production levels, additional wells must be rapidly drilled. Hughes (2014, 10) describes research from the U.S. that "reveals high well- and field-decline rates, which require an escalating drilling treadmill to maintain production. The shale- and tight-gas plays of BC are similar."

BMO Capital Markets (2011)

BMO Capital Markets (2011) developed a 50,000 acre (20,000 ha) development model for the North Montney that is a useful triangulation tool for FNFN territory. It is estimated that some 5 Tcf of gas would be generated from 936 wells in this area over an 18 year period.

The BMO Capital Markets model assumed that 12 wells would be drilled a month until a production level of 630 Mmcf/day was reached, after which production would be held constant at that rate by reducing the drilling level by half to 6 wells a month. The author has replicated this pattern in Table 4 below. The total number of wells is higher in the first row at 1,656 because in this study's modeling, where the gas production rate is required to stay continuous throughout the 20 year time period, whereas in the BMO Capital Markets model it starts to decline after the first 8 or 9 years.

If the productivity of the North Montney (5.2 Mmcf/day IP and EUR of 4.2) was directly comparable to that of FNFN territory shale basins, between 1288 and 7038 wells would be drilled over 20 years to produce the expected LNG-induced gas extraction levels required from FNFN territory, as per Table 4.

Table 4: BMO Capital Markets North Montney Model Extrapolation

	Year 1	Year 2	Year 3	Years 4-20	Total years 4–20	Total years 1–20
BMO model North Montney with IP of 5.2 MMcf/d and EUR 4.2 BCF — continuous production of 630 Mmcf/d	144	144	144	72	1,224	1,656
FNFN LNG-Induced Demand Low Growth — continuous production of 490 Mmcf/d (77.8 per cent of the BMO North Montney model)	112	112	112	56	952	1,288
FNFN LNG-Induced Demand High Growth — continuous production of 2680 Mmcf/d (425 per cent of the BMO North Montney model)	612	612	612	306	5,202	7,038

However, since this study uses a higher 10 Bcf EUR/well metric for FNFN shales, these numbers must be reduced.

17 Nonetheless, Horn River remains attractive due to its higher average EUR/well than other B.C. basins, as shown in section 4.2.2.

- Low LNG-Induced Growth = 1288 * 0.42[18] = 541 wells required in FNFN territory; and
- High LNG-Induced Growth = 7038 * 0.42 = 2956 wells required in FNFN territory.

This triangulates well with some of the other analyst estimates (such as Hughes 2014). It also includes replacement well calculations. Confidence in it is thus moderate to high.

Walden and Walden (2012)

Walden and Walden (2012, 32) calculated "the total number of wells [from the Horn River Basin] needed to sustain an approximate production of approximately 850 Mmcf/day between the years 2015-2017 and then approximately 1,690 Mmcf/day for the years 2018–2035." This aligns well with a mid-range in the expected LNG-induced demand scenario in FNFN territory from the author's Phase 1 report. Walden and Walden (2012) estimated that between 2015 and 2035, approximately 1,750 wells would need to be drilled in the Horn River Basin to sustain the Kitimat LNG facility at 1.69 Bcf/day.

Figure 12 extrapolates from the Walden and Walden (2012) forecast to estimate that FNFN's low end LNG-induced demand level of 0.49 Bcf/day would require 527 wells between 2018 and 2038. To produce 2.68 Bcf/day on average for 20 years starting in 2018, 2881 wells would need to be drilled.

Figure 12: Estimating LNG-induced Wells in FNFN Territory Using the Walden and Walden (2012) Model

18 This proportion was generated by dividing the BMO North Montney estimated EUR/well (4.2 Bcf) by the one used in this study for FNFN territory shale gas deposits (10 Bcf).

The utility of this proxy model is heightened by the fact its 4.5 to 5 Bcf three year cumulative production rate for the modeled wells is relatively close to that which would be expected from this study's 10 Bcf EUR wells. It also focuses solely on activities within FNFN territory, and includes replacement wells in its calculations. Confidence in this estimate as a reasonable proxy for FNFN territory is therefore relatively high.

4.2.5 Estimations from other Shale Gas Jurisdictions

Ziff Energy Group (2012)

Ziff Energy Group (2012) provided evidence that the Haynesville shale gas basin in northeastern U.S. in 2010 produced 4.75 Bcf/day from 1030 wells drilled between 2008 and 2010 (during a basin opening "ramp-up" phase). The same study modeled Horn River using the same three year cumulative well data from the Haynesville experience and found virtually identical production at 4.67 Bcf/day in the third year, indicating that modeled production rates from Haynesville and Horn River are similar.

Including an initial ramp up to reach 4.67 Bcf/day and additional well drilling to stay at 4.67 Bcf/day, it is estimated using Ziff Energy Group (2012) that the Horn River Basin would need to expand by 7915 wells over 20 years. These numbers were later reduced by the appropriate amounts to fit the LNG-induced gas extraction requirements used in this study — 0.49 to 2.68 Bcf/day vs. 4.67 Bcf/day. The following well requirements were initially estimated:

- Low LNG-Induced Growth = 830 wells required in FNFN territory; and
- High LNG-Induced Growth = 4,542 wells required in FNFN territory.

However, the per well production rate of approximately 4.6 Mmcf/day for the modeled wells is lower than what can be expected if FNFN well EUR averages 10 Bcf.[19] Using an estimate that this model has an average Bcf/well of 6.72, the well requirements were adjusted as follows:

- Low LNG-Induced Growth = 873 * 0.672 = 558 wells required in FNFN territory; and
- High LNG-Induced Growth = 4775 * 0.672 = 3,052 wells required in FNFN territory.

Using data from Ziff Energy Group, it is estimated that between 558 and 3,052 wells would be required in FNFN territory over the first 20 years of LNG-induced gas extraction.

The Ziff Energy Group data benefits from being directly based on FNFN territory shale deposits. Despite being less conservative than this study in average EUR/well, it clearly identifies that the Horn River Basin deposits have high productivity, some 35 times greater than conventional WCSB wells and larger than the average Montney unconventional wells. As a result this modeling exercise, like Walden and Walden (2012) inspires relatively high confidence as an accurate projection of FNFN shale deposit well requirements.

19 The 4.6 Mmcf/day well average is estimated for the Ziff Energy Group model based on 4.67 Bcf/day divided by 1030 wells. It is assumed that the wells are first year wells at maximum production. At 4.6 Mmcf/day, each average well, using Mason's 2011 estimate of 25 per cent of total production from a shale gas well in the first year, is expected to have an EUR of 6.72 Bcf.

Mason (2011)

Mason (2011) examined well production profiles for the Fayetteville shale gas play in Arkansas in order to project the scale of well development required to maintain a shale gas production level of 500 Bcf/year (1.37 Bcf/day) for forty years. He argues that these findings can then be scaled to any annual shale gas production level. The Fayetteville shale gas play is comparable to those in FNFN territory in general composition and size (technically recoverable resource of 41-58 Tcf in 2011), but has seen much more development than the FNFN shale basins. By 2010, it was producing about 2 Bcf/day of gas, as much as FNFN and Montney combined in 2013. Average well peak production was 1.85 Mmcf/day, but was growing to 2.2 Mmcf/day, indicating "significant learning curve gains in field exploration and drilling" (Mason 2011, p. 2). Mason identifies an "average well" EUR over 40 years of 1.7 Bcf, substantially lower than expected in FNFN territory.

Mason (2011, 4) uses all of this well data to identify the amount of drilling necessary to sustain a constant level of shale gas production at 500 Bcf/yr (1.37 Bcf/day) over time:

> *"The number of wells to produce 500 bcf of gas in the first year of production is 1220. The number of new well additions to compensate for declines in existing well production ranges from 670 new wells in Year 2 and declines annually to 285 new wells in Years 18-40. The cumulative number of wells to maintain a 500 bcf/year gas production rate for forty years is 14,549."*[20]

What are the potential implications of Mason's work for the LNG-induced gas extraction scenario in FNFN territory? First of all, it should be recognized that the average estimated future well production EUR in FNFN territory is almost six-fold higher at 10 Bcf than that recorded in the Fayetteville play at 1.7 Bcf. Adjustments have been made accordingly.

In addition, because Mason's study is focused on 40 years, assumptions needed to be made to fit this study's 20 year window. Mason's model suggests that the first 20 years of production at 1.37 Bcf/day requires about 8500 wells. This well amount was used as the starting point to calculate that:

- 0.49 Bcf/day over 20 years would require 517 wells at 10 Bcf EUR per well;[21] and
- 2.68 Bcf/day over 20 years would require 2,826 wells at 10 Bcf EUR per well.

Using data from Mason (2011), it is estimated that between 517 and 2,826 wells would be required in FNFN territory over the first 20 years of LNG-induced gas extraction.

One of the strengths of the Mason (2011) study is that it lays out all of its modeling assumptions in such a way that is can be adjusted to FNFN territory shale basin characteristics. The author was therefore able to filter it through the 10 Bcf EUR/well assumptions used to reflect higher likely future FNFN territory shale gas production per well values. In addition, replacement wells are factored into the analysis. However, it is also worth noting that the decline rate is expected to be much higher from FNFN territory than in Fayetteville, meaning replacement wells will be required in shorter order. This factor has not been accounted for in the estimate. Confidence in this proxy study is moderate.

20 Mason also raises the question of whether in the early development stage of a play the most high production core areas are exhausted, leading to potential for diminishing per well returns later in the play's life cycle. However, this may be offset by technological improvements over time that tap additional reserves and remove more of the total available gas per well (for example, Mason also notes that well infilling (down-spacing) and re-fracking may increase total gas recovery by 11 to 18 per cent). In the face of uncertainty about the balance of these issues, the author has not weighed in on these particular forward looking questions.

21 This number was calculated by first dividing 0.49 and 2.38 by 1.37, which identified that the FNFN LNG-induced demand equates to 35.7 and 196 per cent respectively, of the production amount modeled by Mason (2011). This proportion was then multiplied by (8500 * 0.17 = 1445), 1445 being the number of wells expected over 20 years in FNFN territory, given its much higher 10 Bcf EUR/well.

CWC School for Energy (2013)

CWC School for Energy (2013) developed a hypothetical shale gas project with a total production life of 25 years, producing 8 Tcf of gas over that time period. It was estimated that 4,284 wells would be required to generate the gas. Using the data provided by CWC School for Energy on ramp up to an average of 1 Bcf/day of production, this hypothetical shale gas project would require 3616 wells over 20 years, producing 6.75 Tcf over that time period (an average of 0.925 Bcf/day). The author then compared this to the FNFN LNG-induced gas extraction scenarios to come up with the following initial results:

- 0.49 Bcf/day over 20 years would require 1,916 wells; and
- 2.68 Bcf/day over 20 years would require 10,477 wells.

Limitations include the fact that the specific EUR/well used in the model is not identified, reducing the confidence placed in this estimate. The author used the limited information available in the publication to estimate a 3.3 Bcf/well EUR for CWC School for Energy (2013). At 10 Bcf/well it is estimated that the amount of required wells would drop to between 632 and 3,457. However, given the limited confidence in the original EUR/well numbers, overall confidence in this estimate is low.

4.2.6 Summary of Estimates of Required Wells to Support LNG-Induced Gas Extraction from FNFN Shale Basins

Table 5 summarizes information from all 13 triangulation tools used to capture the potential range of required wells in support of the first 20 years of LNG-induced gas extraction in FNFN territory, as well as some of the values and limitations on the extrapolation metric, and a confidence rating. *The author's opinion on the "most confident" metric is italicized.*

Altogether, there are 13 different triangulation tools considered, some of which when examined independently there can be higher confidence invested in than others. In this instance, the author removed any estimates where confidence was very low. This led to the top one and bottom two estimates being removed from consideration, as shown by in Figure 13. The remaining 10 triangulation tools were used to come up with the following estimate of the required amount of wells within the LNG-induced gas extraction scenarios established in the Phase 1 study.

As shown in Figure 13, there is a grouping of 10 estimates between 356 and 731 wells in the low end FNFN LNG-induced gas extraction scenario, and between 1950 and 3995 in the high end FNFN LNG-induced gas extraction scenario. This equates to between 18 and nearly 200 new wells per year.

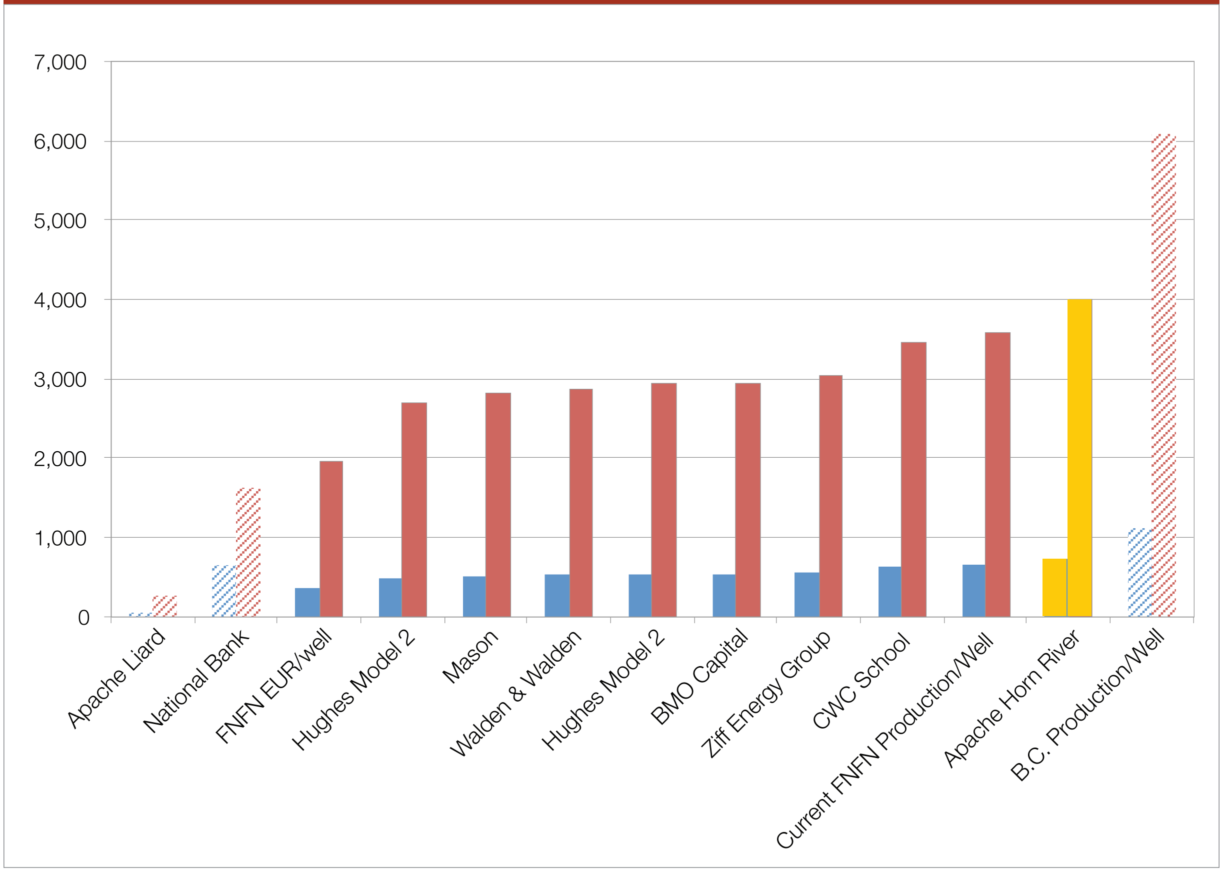
Striped estimates in Figure 13 are those considered "very low" in confidence, not included in the final projection.

One of the benefits of using multiple sources is that a recognizable group of "down the middle" estimates may emerge. Seven of the 13 estimates are tightly grouped between 478 and 632 wells in the low range LNG-induced gas extraction scenario and 2,704 and 3,457 in the high end scenario, a strong indication of the reasonableness of this range of estimates. Despite this, it is the author's opinion for reasons noted above that alongside this grouping, another candidate for "most confident" estimate remains Apache's Horn River Basin modeling from which the author estimated between 731 and 3,995 wells required in FNFN territory over the first 20 years of B.C. LNG exports. This is identified in gold in Figure 13.

Table 5: Summary of Proxy Estimates of Required Wells to Support LNG-induced Demand in FNFN Territory

Proxy study	Estimate of required FNFN wells		Strengths and limitations of proxy study	Confidence level
	Low estimate	High estimate		
Current B.C. average production rates per well	1,112	6,084	Includes conventional and unconventional wells; no replacement wells; EUR not adjusted	Very low
Current FNFN production rates per well	653 to 1,089 (only the lower number is modeled forward, to be conservative)	3,573 to 5,956 (only the lower number is modeled forward, to be conservative)	From FNFN territory but artificially depressed by low gas prices; no replacement wells; higher number includes shale and conventional wells	Low (for low end of each range) to very low (for high end of each range)
EUR/well estimates (the author adopted 10 Bcf/well EUR)	356	1,950	Reflects estimated average EUR/well in FNFN territory, but this is higher than historic; no replacement wells	Low
Apache's Liard Basin Development Model	50	265	Based on unheard of high EUR of 74 Bcf/well; small sample size; no replacement wells	Very low
Apache's (KM LNG 2010) Horn River Basin Model	*731 (reduced by 19 per cent to reflect "shrinkage" in original model)*	*3,995 (reduced by 19 per cent to reflect "shrinkage" in original model)*	*Horn River Basin data used; realistic 12 Bcf per 15 frac well and an IP of 10.2 MMcf/day; includes replacement wells*	*Moderate to high (highest confidence)*
National Bank (2013)	650	1,625	Not pinned to Phase 1 estimates; uses a simple 10 and 25 per cent calculation; no replacement wells	Very low
Hughes (2014) Model 1 — Average wells per year extrapolation	539	2,949	Specific to northeast B.C. -LNG demand; EUR/well adjusted; includes replacement wells but also includes domestic demand	Moderate to low
Hughes (2014) Model 2 — Visual approximation from tabular information	478	2,704	Specific to northeast B.C. -LNG demand; EUR/well adjusted; includes replacement wells; visual analysis of graphical data	Moderate
BMO Capital Markets (2011)	541	2,956	EUR adjusted; data from northeast B.C; includes replacement wells	Moderate to high
Walden and Walden (2012)	527	2,881	Horn River Basin data used; EUR adjusted	Moderate to high
Ziff Energy Group (2013)	558	3,052	Horn River Basin data used; EUR adjusted	Moderate to high
Mason (2011) Fayetteville well production profiling	517	2,826	EUR adjusted; does not account for higher FNFN decline rates; includes replacement values	Moderate
CWC School of Energy hypothetical shale gas deposit	632	3,457	EUR assumptions rounded up to 10 Bcf/well, but original EUR used is unknown	Low

Figure 13: Range of Estimates of Number of Wells Required in FNFN Shale Basins to Support LNG-Induced Gas Extraction, 2018 to 2038



Estimating the Number of Required Well Pads

Most estimates of gas production effects, whether they are economic or environmental, start from well numbers required (e.g., Hughes 2014; Walden and Walden 2012). This focus has been expanded in this case to estimation of the number of well pads required. This is due to the high likelihood that in the future, most hydraulically fractured shale gas wells in FNFN territory, which will almost certainly continue to be the primary method used into the future, will use multi-wells per pad platforms.

Information from industry[22] and the B.C. OGC indicates that between eight and 16 wells per pad will be the norm over the next 20 years from FNFN shale basins. Thus, if 1,600 wells are required to fuel LNG-induced gas extraction, the number of well pads required would be between 100 (16 wells per pad), 133 (12 wells per pad), and 200 (eight wells per pad). For the sake of simplicity, the author chose the median — 12 wells per pad.[23] Currently, the average ratio of wells per pad is lower[24], but these higher numbers are conservatively adopted to reflect rapidly changing technology.

22 For example, Groat and Grimshaw (2012) estimate wells per pad at between 10 and 16 for shale gas development, while B.C. OGC (2013a) suggests that up to 16 wells per pad have been drilled in the Horn River Basin. In addition, Apache Corporation's 2012 "Liard Basin Development Model" uses 12 wells per pad as a modeling assumption.

23 The author encourages other studies to refine this technique and use different wells per pad estimates as they become relevant.

24 According to the B.C. OGC online shape file database (www.bcogc.ca/public-zone/gis-data), 2011 was the first year in FNFN territory where the well to well pad ratio exceeded 2:1.

Table 6 identifies the estimated required number of well pads for the identified range of required wells, through the simple calculation of 12 wells per pad.

Table 6: Estimated Well Pads Required to Support LNG-induced Demand

Well required in…	Well pads required
Low Growth LNG-induced Demand Estimate (356 to 731)	30 to 61
High Growth LNG-induced Demand Estimate (1950 to 3995)	163 to 333
"Most Confident" Estimate (731 to 3,995)	*61 to 333*

In summary, triangulation from a wide variety of secondary source materials suggests that LNG-induced gas extraction alone will require between 356 and 3,995 wells be drilled in FNFN territory between 2018 and 2038, with the most likely amount being between 731 and 3,995 wells. This will require the clearing and construction of between 30 and 333 large 12-wells per pad complexes in FNFN territory, with the most confident amount being between 61 and 333 well pads.

4.3 ESTIMATING OTHER PHYSICAL WORKS AND ACTIVITIES REQUIRED

After establishing a range of required wells and well pads for different LNG-induced gas extraction scenarios in FNFN territory, the study then turned to estimating the total amount of physical works and activities required in support of this additional gas extraction. In some cases, this can be calculated on a per well or per well pad basis. In other cases, such as estimation of the number of gas plants required or work camps required, extrapolation from other sources (e.g., per unity of production estimates for gas plants) and informed estimates — qualitative and/or quantitative — was required.

As noted in Section 2.1, two key methods were used to bound estimates: extrapolation from experience in FNFN territory shale basins to date, and data from proxy studies.

4.3.1 Modeling Forward — Using Current FNFN Activity Level Data to Estimate Future Activity Levels per LNG Scenario

The author worked with the FNFN Lands Department's GIS Technician to identify the degree to which gas activity has impacted on FNFN territory to date. Some of the results are included in Section 3.3 of this Phase 2 Report. Using data from the same B.C. OGC's on-line information base the author was able to calculate the amount of specific types of disturbance that have occurred in (a) core FNFN territory[25] and (b) in the shale gas basins in FNFN territory per well to date in the "shale gas era" — between roughly 2006 and 2013.

25 The area shown outlined in black in Figure 5.

Per well pad metrics were not calculated because only very recently have large numbers of wells been developed per well pad, so relying on well pad information to date would likely not closely approximate the future. FNFN's historic production rate data was also deemed unlikely to be a very accurate proxy, given that the depressed nature of North American gas prices since 2009 has shuttered in much development and production potential in FNFN territory, so is not included herein. Table 7 identifies the findings.

Caution should also be taken in that while the well and other activities date may be correlated, the relationship may not be causal. This means that in some cases, it cannot be predicted with confidence that the existing relationship between wells and, for example, km of pipeline will grow in the future at the same rate as the current relationship. It is also important to remember that this data is limited to eight years only; it does not reflect total gas activity to date in FNFN territory. For example, some 128,500 km of seismic lines have been cleared in core FNFN territory over time, much higher than the numbers reported herein. In addition, some data is non-comparable. For example, B.C. OGC data suggests that over 3,000 borrow sites have been developed in the three FNFN shale gas basins between 2006 and 2013. However, since the total for the larger core FNFN territory is lower at 2101 borrow sites, this study adopts the smaller, more conservative number only.

It is worthy of note that not all facilities are identified in this analysis. Numbers could not be found for facilities including batteries for storage of liquids, dehydrators, flare sites and metering sites. The absence of these facilities from this study's calculations likely again reduces the total effects loading modeled.

Table 7: Relationship Between Wells and Other Gas Infrastructure Developed in FNFN Core Territory, 2006 to 2013 (using B.C. OGC online data)

Physical work type	Total FNFN core territory 2006–2013	Total in FNFN shale basins 2006 to 2013	Per well equivalent (FNFN core = 1,139; FNFN shale = 892)
Wells	1,139	892	n/a
Well Pads	536	299	FNFN Core = 2.12 wells per well pad FNFN Shale = 2.98 wells per well pad
Gas Industry Roads	10,351 km	4,662 km	FNFN Core = 9.09 km per well FNFN Shale = 5.22 km per well
Pipelines	9,838.65 km[1]	Unknown	FNFN Core = 8.64 km per well
Seismic Line	75,354 km	57,428	FNFN Core = 66.15 km per well FNFN Shale = 64.38 km per well
Water Withdrawals – Locations	1,992 locations	1,194	FNFN Core = 1.75 withdrawal locations/well FNFN Shale = 1.34/well
Water Withdrawals – Extraction	22,928,992 m^3 (22.93 billion litres)	19,584,715 m^3 (19.58 billion litres)	FNFN Core = 20,131 m^3 (20.1 million litres) per well FNFN Shale = 21,956 m^3 (21.96 million litres)
Water – Deep Disposal Locations	60	14	FNFN Core = 19 wells per water disposal location FNFN Shale = 64 wells per location

Table 7 continued			
Physical work type	**Total FNFN core territory 2006–2013**	**Total in FNFN shale basins 2006 to 2013**	**Per well equivalent (FNFN core = 1,139; FNFN shale = 892)**
Water – Storage/ Dugouts	1,543	462	FNFN Core = 1.35 water storage locations per well FNFN Shale = 0.52 per well
Water Treatment Facilities	3	3	1 water treatment facility per 300 to 400 wells
Camps	287	257	One camp per 3.5 to 4 wells
Gas Plants	21	5	One gas plant per 54 to 170 wells
Compressor Stations	93	25	One compressor per 12 to 36 wells
Borrow Pits	2,101	Unknown	1.84 borrow pits per well
Waste Disposal Sites	465	222	One disposal site per 2.4 to 4 wells

4.3.2 Data from Proxy Studies

There has been a dearth of recent proxy studies looking at current — or modelling future — additional infrastructure requirements to support shale gas extraction. Therefore, in addition to using FNFN's own experience (primarily in the Horn River Basin), the author was limited to examining previous modeling exercises for gas development cumulative effects, such as work in the Peele River Basin (Holroyd and Retzer 2005), along with limited data from a few newer proxy studies of shale gas development scenarios, to triangulate reasonable predictions of likely per unit activity levels. Select results are identified under the headings below and captured alongside the FNFN 2006-2013 case study in Table 8.

Seismic lines: Holroyd and Retzer (2005) estimate 8 to 17 km of seismic may be required per well in conventional gas deposits. Braun and Hanas (2005) estimated 870,000 miles of seismic for 103,806 wells in Alberta, or about 8.5 miles (14 km) of seismic per well. In the FNFN instance, estimating this metric per well pad makes more sense given expectations for multiple wells per pad.

Roads: Holroyd and Retzer (2005) estimate 2.5 to 9 km of seismic may be required per well in conventional gas deposits. Again in the FNFN instance, estimating this metric per well pad makes more sense given multiple wells per pad.

Pipelines Required: Determining how much additional pipeline capacity will be required to move gas from FNFN territory to LNG facilities in B.C. is a difficult matter. It is beyond the scope of this study to estimate how much excess capacity there is in existing FNFN territory infrastructure to move gas toward market. What is known is that the current infrastructure in place for FNFN would support only the lowest possible scenarios of LNG demand. For example, BC Hydro (2013) notes that existing pipeline capacity is insufficient under mid- to-high-range future scenarios for Horn River Basin that are similar to those estimated for LNG-induced demand.

In virtually any scenario where there is LNG-induced demand for FNFN gas, additional pipeline infrastructure will be required through and out of FNFN territory.

Some proxy study data is of value in estimating the amount of pipeline required per unit of physical work or production. Braun and Hanas (2005), using Alberta data, identify about 1.8 miles (3 km) of pipelines per well in Alberta as of 2000. Johnson (2010) estimate that in the Marcellus shale in Pennsylvania, there are 1.65 miles (2.7 km) of gathering pipelines per well pad. Holroyd & Retzer (2005) estimated 9–20 km of pipeline for each completed well.

In relation to production, B.C. OGC (2012b, 4) reported that in 2011, there were 18,674 km of natural gas pipelines and 11,878 km of sour natural gas pipelines operating in B.C. Given the approximately 4.0 Bcf/day of raw gas that was being produced in 2011, this equates to about 7500 km of pipeline for every Bcf/day of production. This study assumes a rate only half this for future expansion, 3750 km of pipeline for each new Bcf/day of production, discounting for use of excess capacity in existing pipelines and also in recognition of increasing capacity in newer, wider diameter pipelines.

Facilities required: A couple of metrics were considered. Environmental Law Centre (2013) estimates that compressor stations are installed at intervals between 48 to 112 km along pipelines. Braun and Hanas (2005) calculate 659 gas plants in Alberta for 103,806 operating wells as of 2000, or one gas plant per every 158 wells.

Drill rigs required: Ratner (2013) estimates that Montney producers will require no more than 20 drill rigs per Bcf/day of LNG-directed gas they produce. In the same article, it is suggested that as few as 8 to 10 newly-built pad drilling rigs will be required for each Bcf per day of Canadian LNG-induced gas production.

Frac Sands Mining: Development of "frack sands" sources in northeastern B.C. would require open pit/quarry style mining, creating additional ground, water and wildlife impacts. The amounts that may be required are quantified in section 5.1.4; the number of facilities required to mine the materials is as yet unknown.[26]

4.3.3 Summary of Physical Works and Activity Levels Required

Findings of estimated physical works and activity requirements per well and per well pad from the FNFN core territory case study and the proxy studies from other jurisdictions are listed in Table 8, along with the author's selected value to take forward to the effects modeling step. The chosen value in each case is triangulated from the available information, with explanatory notes where necessary.

26 Information filed by Canadian Silica Industries (2012) for its Komie North Sand Project estimated extraction of 240,000 tonnes/year for 12 years on a 206.5 hectare site.

Table 8: Summary of Estimates Average Physical Works Required per Well/Pad			
Physical work type	FNFN case study (2006–2013)	Proxy studies	Chosen modeling metric for FNFN LNG demand study
Wells per well pad	2.12 to 2.98	n/a	12 wells per pad, for reasons identified in Section 4.2.6
Gas industry roads	5.22 to 9.88 km per well	2.5 to 9 km	5 km per well pad or 0.43 km per well (lower than current rate due to existing infrastructure)
Pipeline	8.64 km per well	3 to 20 km per well; 7,500 km per each Bcf/day of production	Two metrics: 1) 4.5 km per well pad (reflects discount due to existing infrastructure); 2) 3,750 Km per each additional Bcf/day
Seismic	64 to 66 km per well	8 to 17 km	48 km per well pad or 4 km per well (much lower than current rate due to already completed seismic work in many places)
Water withdrawals – locations	1.34 to 1.76 water withdrawal locations per well	n/a	1.76 water withdrawal locations per well (higher number to reflect growing water requirements)
Water withdrawals – extraction	20 to 22 million litres per well	31 to 80 million litres per well	31 to 80 million litres per well (more recent wells have trended radically upwards)
Water — disposal locations	19 to 64 wells per water disposal locations	n/a	19 wells per water disposal location (lower ratio to reflect growing water requirements)
Water – storage/ dugouts	0.5 to 1.33 wells per water storage location	n/a	2 water storage locations per well pad (note measured by well pad)
Water treatment facilities	One water treatment facility per 300 to 400 wells	n/a	One water treatment facility per 350 wells (median value)
Work camps	One work camp per 3.5 to 4 wells	n/a	One work camp per 20 wells (reflecting already existing infrastructure)
Gas plants	One gas plant per 54 to 170 wells	One gas plant per 158 wells	Two metrics: 1) one new gas plant per 150 wells; 2) one new gas plant per each 600 Mmcf/day new production
Compressor stations	One compressor station per 12 to 36 wells	One compressor station for every 48 to 112 km of pipeline	One compressor station for each 112 km of new pipeline
Borrow pits	1.84 borrow pits per well	n/a	1.5 borrow pits per well (reflecting existing infrastructure)
Waste disposal sites	One disposal site per 2.4 to 4 wells	n/a	One disposal site per 4 wells
Active drill rigs at any one time	n/a	8 to 20 drill rigs per Bcf	14 drill rigs per Bcf (the median estimate)

From the chosen modeling metric(s) for each category, Table 9 was developed, projecting total physical works requirements for low and high growth LNG-induced demand scenarios.

Table 9: Estimated Total Physical Works and Activities Required in Support of Low and High LNG-induced Gas Extraction Scenarios for FNFN Territory, 2018 to 2038

Physical Work Type	490 Mmcf/day requires...	2.68 Bcf/day requires...
Wells	356 to 731	1,950 to 3,995
Well pads (12 wells per pad)	30 to 61	163 to 333
Gas industry roads (5 km per well pad)	150 to 305 km	815 to 1,665 km
Pipelines (two metrics: 4.5 km per well pad and 3750 km/Bcf)	135 to 275 km (1,838 km using km/Bcf metric)	733 to 1,499 km (10,000 Km using km/Bcf metric)
Seismic line (48 km per well pad)	1,440 to 2,928 km	7,824 to 15,984 km
Water withdrawals — locations (1.76 per well)	627 to 1,287	3,432 to 7,031
Water withdrawals — extraction (31 to 80 million litres per well)	11 to 58.5 billion litres	60.4 to 320 billion litres
Water — disposal locations (one for every 19 wells)	19 to 38	103 to 210
Water — storage/dugouts (two for every well pad)	60 to 121	326 to 666
Water treatment facilities (one for every 350 wells)	1 to 2	6 to 12
Camps (one new camp per 20 wells)	18 to 36	98 to 200
Gas plants (two metrics, one new gas plant per 150 wells; and per 600 Mmcf/day raw gas)	3 to 5; if measured by large sales gas plants, one new gas plant required	13 to 27; if measured by large sales gas plants, five new sales gas plants required
Compressor stations (one per 112 km of new pipeline)	2 to 16	6 to 90
Borrow pits (1.5 per well)	534 to 1,097	2,925 to 5,993
Waste disposal sites (1 per 4 wells)	89 to 181	489 to 999
Active drill rigs at any one time (14 per Bcf/day of new production)	7	40

Expected future seismic line numbers, in particular, are lower than historic numbers. This reduction in initial seismic activity is a reasonable expectation for a maturing gas sector where a large amount of seismic geophysical exploration activity has either already been completed in certain areas (e.g., the Horn River Basin) or is in the process of being completed now, in large part to prove up resources to fuel the LNG sector. A good example of this is Apache Corporation's Liard 3D program filed for in 2013. This program called for 3 to 4.25 metre seismic line cutting of 3924 km over a 936 km^2 area, well over 90 per cent of it "new cut" (pers. Comm., FNFN Lands Department, April 2014).

SECTION 5

Calculating the Effects of LNG-Induced Demand

5.1 ESTIMATING TOTAL LNG-INDUCED EFFECTS LOAD BY KEY INDICATOR

Exploration, development, production and transportation of natural gas will all require new physical works and activities to be conducted on FNFN territory as a B.C. LNG export sector emerges. These physical works and activities and their potential effects were described in general terms in Section 3. An effort was made to quantify the actual physical works and activities necessary in an LNG-induced demand scenario in Section 4. Section 5 examines the range of effects outcomes these changes would bring, using a variety of key indicators.

There have been few efforts to quantify what future gas activity scenarios will mean on the ground in northeast B.C. Existing cumulative effects assessment effort such as B.C. OGC's Area-Based Analysis (2013a), tends to focus on existing effects and is not forward looking. The Forest Practices Board (2011) provides one limited forecasting example, modelling a projection of potential future growth effects in the Kiskatinaw River Watershed, but mixed conventional and unconventional deposits and the more advanced pre-LNG development activities in that model make it largely unsuitable as a proxy for the FNFN case. And this remains the only modeling exercise for effects on the ground available to date.

As a result of limited previous work on this topic and the limited scope of this Project, this study focused instead on finding credible "per unit of physical work and activity" land use and input use requirements and multiplying this by the expected number of those physical works and activities required in the LNG-induced demand scenarios identified in Section 4.

For a hypothetical example, if a typical large multi-well complex covers some 9 hectares, if there are 75 well complexes required, the direct physical footprint would be expected to be (9 * 75 = 675 hectares). In addition, an additional Zone of Influence (ZOI) can be calculated. Using Johnson et al.'s (2010) estimations from another shale gas basin, it is calculated that for each hectare of physical clearing there is an additional 2.41 hectares of ZOI. In the above hypothetical example, the total disturbance (physical footprint plus ZOI) would be 675 + (2.41 multiplied by 675) = 2,301 hectares.

Table 10 identifies average disturbance and process input metrics for different physical works and activities calculated by information from B.C. OGC applications (e.g., hectares of clearing for different work types) reviewed by FNFN Lands Department staff and gathered from a variety of studies, and the author's chosen metric for this effects modeling exercise. Data that could be characterized in area-based terms, such as well pad complexes and facilities, use hectares (ha) or square kilometres (km^2). Data that can more effectively be characterized as linear disturbances are in total km or km/km^2.

Table 10: Estimates of Scale of Land Use/Inputs Required per Gas Sector Activity Type

Physical work type	FNFN examples or proxy study estimates	Chosen metric for FNFN LNG demand study
12 well pad complex	1 to 16 hectares (clearings from 100 to 400 metres square); based on data from B.C. OGC permit applications reviewed by FNFN Lands Department	9 hectares (300 by 300 metres square)
Seismic (width)[a]	2.7 – 5 metres (e.g., Forest Practices Board (2011) says lines may be 4 metres in width)	3 metres
Roads (ROW width)	25 metres (2 lane gravel road — Forest Practices Board 2011); 10 metres (Government of Yukon 2005)	20 metres
Pipeline (ROW width; only a certain per cent of new cut considered a new linear disturbance)	20 metres (Forest Practices Board 2011; assumed only 15 per cent would require new cut); can be as high as >50 metres for large new sales gas pipelines (WCGT 2012)	20 metres, with 33.3 per cent requiring new cut
Zone of Influence (ZOI)	An additional 2.41 hectares on top of physical footprint (Johnson et al. 2010)	An additional 2.41 hectares on top of physical footprint
Gas plant	78 hectares (using the Fortune Creek Gas Plant example)	50 hectares (clearing approx. 700 by 700 metres)
Compressor stations	Compressors averaged 19 ha in B.C. OGC Applications viewed	10 hectares (250 by 400 metres)
Storage sites, borrow pits, water disposal facilities	In B.C. OGC Applications reviewed, borrow pits averaged 2.33 ha; water disposal 1.75 ha; storage sites 3 ha	2 hectares (100 by 200 metres)
Water storage sites/dugouts	Up to 11.2 hectares (Campbell and Horne 2011); 4 ha (B.C. OGC applications)	4 hectares (200 by 200 metres)
Waste disposal facilities/camps	0.5 ha (B.C. OGC applications)	0.5 hectares
Water treatment facilities	n/a	9 hectares (300 by 300 metres)
Water use (millions of litres per well)	30 to 90 million litres[b]	30 to 81 million litres per well
Frac sands (tonnes per well)	4,000 tonnes per well (IEA 2012a & 2012b); 3,700 to 4100 tonnes (B.C. OGC 2013b)	4,000 tonnes per well

Table 10 continued		
Physical work type	**FNFN examples or proxy study estimates**	**Chosen metric for FNFN LNG demand study**
Frac additives (e.g., chemicals; litres per well)	0.5 per cent of liquid inputs (99.5 per cent water — Linley 2013); 1 per cent of liquid inputs (IEA 2012a; IEA 2012b)	1/200th of water use amount (0.5 per cent)

Notes:
[a] This study has not included other access issues on top of seismic in disturbance modeling. For example, Apache's Liard 3D seismic plans (Apache Corporation 2013) showed that new access, heli-pads, staging areas and push outs would cause clearing of 10 per cent more land on top of the seismic program.
[b] Environmental Law Centre (2013) estimates 30 million litres per well in FNFN shale gas basins; Johnson (2012) estimates 34.7 to 81 million litres; Johnson (2010) estimates 60 million litres; B.C. OGC (2013b) estimates over 60 million litres in the Horn River Basin and 43 million in Cordova and Campbell (2010) estimates up to 90 million litres per well.

Using these estimates of required disturbance and inputs, alongside the LNG-induced physical works and activities established in Section 4.3.3, Table 11 calculates some of the potential LNG-induced effects loads. As noted previously in Table 9, the Low Growth scenario would require between 30 and 61 multi-well pad complexes and 356 to 731 wells, while the High Growth scenario would require between 163 and 333 well pads and 1,950 to 3,995 wells.

Table 11: Estimating Total LNG-induced Effects Loads in the Three FNFN Shale Gas Basins, by Key Indicator

Key effects indicator	Low growth — 490 Mmcf/day requires…	High Growth — 2.68 Bcf/day requires…
Total linear disturbance (roads plus 33 per cent of pipelines plus seismic)	1,635 to 3,840 km	9,083 to 20,982 km
Non-seismic linear disturbance (roads plus 33 per cent of pipelines)	195 to 918 km	1,059 to 4,998 km
Total direct areal disturbance[a]	3,053 to 6,813 hectares (30.53 to 68.13 km^2)	16,441 to 37,457 hectares (164.41 to 374.57 km^2)
Total impact footprint (physical footprint plus ZOI 2.41 times larger)	10,411 to 23,234 ha (104.11 to 232.34 km^2)	56,063 to 127,727 ha (560.63 to 1277.27 km^2)
Water usage (wells only)	11 to 58.5 billion litres	60.4 to 320 billion litres
Frac sands required	1.42 to 2.9 million tonnes	7.8 to 16 million tonnes
Frack chemical additives required	55 to 293 million litres	302 million to 1.6 billion litres
GHG emissions (CO^2e – see section 5.1.5)	2.6 million tonnes per year	15.1 million tonnes per year

Note: [a] This was calculated by adding the total expected areal disturbance in square km to the square km calculated for linear disturbances by type (e.g., 100 km of 20 metre wide roads = 2 km^2 or 200 hectares).

Please note that Table 11 estimates only additional effects associated with LNG-induced demand, not existing effects or effects associated with North American gas supply activities in FNFN territory. In fact, these effects would all relate to one another as combinatory, or cumulative, effects. For example, the estimated 1635 to nearly 20,000 km of additional linear disturbance will be added to an existing amount of over 78,000 km of linear disturbance in the three FNFN shale gas basins from 2002 to 2012, impacts of a similar nature prior to 2002, and continuing linear disturbance effects ongoing between 2013 and 2017, prior to the start date for this modeling exercise.

The following sub-sections drill deeper into potential implications of these changes for:

- Linear disturbance effects (section 5.1.1);
- Areal disturbance effects (section 5.1.2);
- Water use, quality and quantity (section 5.1.3);
- GHG emissions (section 5.1.4); and
- Potential effects on the human environment (Section 5.2).

All key indicator estimates are limited to the first 20 years of the LNG export sector, from approximately 2018 to 2038.

5.1.1 Increased Linear Disturbance of FNFN Territory

This study estimates that LNG-induced gas extraction will add between 1,635 and 20,982 km of linear disturbance to the three shale gas basins in FNFN territory. This includes 1,440 to 15,984 km of seismic line cutting and 195 to 4,998 km of wider road and pipeline development.

Roads tend to be substantial and effectively permanent linear features. Once developed, they are rarely fully decommissioned, and become sources of access for harvesters, recreationalists and other industrial interests (e.g., further gas sector companies or forestry companies). Pipelines are also long-term (50 plus years) cleared areas that increase access and predation risks through long lines of sight. Some research indicates that historic seismic lines do not establish re-growth quickly (see section 3.2.2). However, recent reductions in line width and improvements in seismic line cut methods (e.g., not using cat-cut lines and reducing line of sight) may reduce the effects of these gas sector activities in the future. Thus, one of the metrics identified in Table 13 is “non-seismic linear disturbance,” to reflect the heightened potential effects loading of roads and pipelines versus seismic clearing.

The locations of roads and pipelines will of course be dependent on which shale basins are preferentially developed. It is safe to assume that the intensity of added linear disturbance in the Liard Basin, given current infrastructure deficits there, would likely be higher than in the already heavily industrialized Horn River Basin. The amount of additional seismic line cutting in the Horn River Basin and the Cordova Embayment is assumed to be relatively small, given the extensive amount that has already occurred. However, in the Liard Basin, the relative lack of up-to-date seismic information likely requires extensive additional seismic programs on an extensive scale as a “basin opening” activity. Much of this activity will likely occur prior to the time frame outlined in this study (2018–2038) even starts.

5.1.2 Increased Areal Disturbance of FNFN Territory

This study estimates that LNG-induced gas extraction will add 30.5 to 374.6 km^2 of direct areal disturbance to the three shale gas basins in FNFN territory. This direct physical footprint includes well pad clearing, clearings for other facilities, and linear developments converted to areal disturbance. In addition to this direct physical footprint, the findings identify a total impact footprint (including a disturbance ZOI) of 104 to 1277 km^2.

Please note this study did not use a 250 metre buffer around impacted areas, such as that recommended by Environment Canada for assessment of impacts on woodland caribou habitat, which would expand the ZOI significantly.

While multi-well pads have some benefits, reduced size of individual clearings is not one of them. Hydraulic fracturing activities on multi-well pads requires industrial clearings as large as 400 metres by 400 metres (16 hectares), compared to traditional single vertical well pads which are one hectare in size or smaller. The implications of this shift to a smaller number of larger industrial complexes on the land in the shale gas sector have not been adequately studied to date in FNFN territory.

5.1.3 Increased Water Usage

> *Environmental Law Centre (2013, 25) suggests that if 6,500 total wells are required to fuel LNG-induced demand, "the industry will need to use and render toxic more than 691 million cubic metres [691 billion litres] of water."*

This study estimates that LNG-induce gas extraction will require the withdrawal and use of 11 to 320 billion litres of water from surface water bodies and ground water sources in the three shale gas basins in FNFN territory.[27] An additional 60 to 666 water storage facilities and a wide variety of other water treatment and disposal sites will also likely be required in support of water management.

It is estimated from different sources that between 20 to up to 90 million litres of water are required per well in FNFN territory, with the most likely range estimated herein as between 30 and 81 million litres. As with GHG emissions (see section 5.1.5), water usage per well in FNFN territory is higher than in the Montney, where it is estimated that just over 11 million litres are used per well (B.C. OGC 2013b). Johnson (2012) estimates the range of Horn River gas well requirements are more than ten times greater than the Montney average and the highest amount by far of any North American unconventional play.

With an increasing number of wells per pad and fracs per well, both of which require increasing amounts of water,[28] amounts of water unprecedented in North American natural gas development are likely to be required in FNFN territory. The implications of this intensive use of water for surface and ground water sources are not yet fully understood. Concerns include the management of contaminated process water and surfacing saline ground water, long-term ground water and surface water contamination, and the effects of surface water withdrawals on water levels in area lakes and streams, critical ecological and Aboriginal use locations.

27 This estimate includes the use of water in hydraulic fracturing of wells only and does not include any other uses of water by the gas sector. In reality, seismic exploration, roadwork, extraction and processing of frac sands, and testing of pipelines, among other activities, also require water. Further research into how much water is being used for these activities would be an important contribution to cumulative effects assessment in the region.

28 Johnson (2009) suggests that a single frac job may take a day and use 9.5 and 13.6 million litres of water.

5.1.4 Increased Use of Process Additives

This study estimates that LNG-induced gas extraction will require the use of between 1.42 and 16 million tonnes of frac sands and other proppants in the three shale gas basins in FNFN territory. Much of it will likely be sourced from open pit mines in FNFN territory. In addition, 55 million to 1.6 billion litres of chemical additives would be used in the hydraulic fracturing process.

The effects of frac sands mining may add to areal effects loading in the future in an as-yet to be calculated way. Hickin et al. (2010) identify seven major locations within FNFN territory of unconsolidated sand deposits that may house extractable frac sands. Demand for this hydraulic fracture proppant has increased "because of the enormous volume of frac sand required to develop unconventional shale gas resources" (Hickin et al. 2010). Several deposits are located in close proximity to existing gas development activities, including frac sands mines proposed in the Komie and Dazo Creek areas (Canadian Silica Industries 2012), which FNFN Lands Department has noted are areas with good caribou habitat and harvesting habitat for FNFN members (Lowe 2014). While this proximity makes these frac sands sources economically attractive, it also increases the potential for Project-specific and cumulative effects on the environment in these already substantially impacted areas. Frac sands mines would be open pit mines, with attendant land clearing, road making, air quality, wildlife and other effects on their surroundings.

Management and long-term effects of large amounts of a wide range of chemicals in hydraulic fracturing, in the range of one litre of chemical inputs per 200 litres of water, is an ongoing concern beyond the scope of this study to address.

5.1.5 Increased GHG Emissions

> *"British Columbia appears caught between a rock and a hard place in balancing its hunger for a burgeoning liquefied natural gas industry and meeting its ambitious 2007 greenhouse gas pollution-reduction targets" — Meissner (2013)*

This study estimates that LNG-induced gas extraction from FNFN territory will generate between 2.6 and 15.1 million tonnes per year of carbon dioxide equivalent GHG emissions (CO_2e) over the first 20 years of the B.C. LNG sector.

CO_2 and other GHG emissions have been closely linked to climate change, which may see catastrophic environmental effects at the global and provincial levels. Extreme weather events, changes in the hydrologic regime, and other impacts will occur as warming occurs. A current example of effects of climate change in B.C. is the effect of massive forest losses and adverse economic and environmental effects of mountain pine beetle infestation.

Using emissions levels reported to the United Nations, wherein carbon offsets are not considered, it is expected that B.C. LNG production system (upstream, midstream and downstream elements) may "rival the emissions of neighbouring Alberta's oil sands" (Meissner 2013). This will make it very difficult if not impossible to meet B.C.'s legislated emissions reduction targets of 33 per cent by 2020, let alone the 80 per cent reduction sought for 2050. The Pembina Institute (2013, 1) suggests based on initial modeling using projected volumes of BC LNG that "it is clear that even modest development will have a material impact to the overall emissions in the province."

CO_2 emissions from FNFN shale gas formations are much higher than elsewhere in the WCSB. This CO_2 must be removed from the raw gas stream before it can be transported as sales gas to an LNG facility. This is accomplished at a gas plant. Under current B.C. regulations, this formation CO_2 can be (and in almost all instances is) vented directly to the atmosphere, without payment of a carbon tax or any other punitive requirement. This direct venting to the atmosphere is currently and would continue to be one of the biggest contributions to the total GHG emissions attributable to LNG-induced gas extraction from FNFN territory.

Overall, The Pembina Institute (2013) and Clean Energy Canada (2013) both estimate that almost one tonne of CO_2e (0.88 tonnes to be exact, in the case of the former) will be released into the atmosphere for every tonne of LNG exported from B.C.[29] Of this, the largest portion (16.5 million tonnes of CO_2e, or 0.688 million tonnes CO_2e per mtpa of LNG) would come from upstream emissions from extracting and processing natural gas, prior to transportation by pipeline. Using a conservative assumption that all pipeline transportation emissions will occur outside FNFN territory (not the case), the author calculated the proportion of LNG production system CO_2e emissions attributable to upstream gas extraction from FNFN territory to be in a range of between 2.6 and 15.1 million tonnes per year in support of the B.C. LNG export sector.[30]

It is worth noting that this number is conservative, given that FNFN CO^2e emissions are likely to be much higher than the B.C. average, given the much higher CO^2 content in shale gas deposits in FNFN territory.

Even using the conservative estimates, it is clear that the GHG emissions profile of LNG-induced demand in FNFN territory will be significant in B.C. and even national terms. Indeed, at the higher end (15.1 million tonnes CO_2e), the amount of GHG emissions from upstream LNG-induced demand in FNFN territory alone could in fact exceed B.C's 2009 GHG emissions from the natural gas extraction and processing sector (13.3 million tonnes CO_2e — Campbell and Horne 2011).

The implications of LNG-induced demand to B.C.'s GHG emissions, even if measured only in terms of extraction of gas from FNFN territory, are significant. 15.1 million tonnes CO_2e per year, the high end estimate, is over 25 per cent of BC's total 2011 GHG emissions, and would represent over a third of the amount of total GHG emissions allowed under B.C.'s legislated 2020 target of 43.5 million tonnes. As suggested by The Pembina Institute (2013, 2), "meeting the GHG reduction targets will be very implausible if even a few of the proposed LNG facilities are built."

The Pembina Institute is not alone in raising alarms regarding GHG emissions. B.C. Hydro (2013, 2E-20) points out that given the 12 per cent of Horn River Basin gas taken up by CO_2: "as compared to the target GHG reduction in the *Greenhouse Gas Target Reduction Act* of 46 mega [million] tonnes in 2020, the potential GHGs from the HRB [Horn River Basin], alone, would have a material impact." B.C. Hydro estimates that by 2020, under its Horn River Basin gas production growth scenarios, formation CO_2 produced would equate

29 This number only includes sources of emissions from upstream, midstream (pipelines), and LNG facilities themselves. It *does not* include the emissions from the customers in Asia burning B.C. gas, which would be much higher. The Pembina Institute (2013) estimates that 24 million tonnes of B.C. LNG would generate 62 million tonnes of CO_2e overseas, bringing the total life cycle emissions to 83.2 million tonnes CO_2e, or 3.47 tonnes per tonne of LNG export. It is worth noting as well that The Pembina Institute's estimates of emissions from operating the LNG plants (3.4 million tonnes CO_2e per 24 million tonnes LNG) may well be conservative. The EIS/Application for Progress's Pacific Northwest LNG facility in Prince Rupert, designed for a throughput of 19.2 million tonnes of LNG per year, estimates it could emit as much as 5.28 million tonnes of CO_2e (Pacific Northwest LNG Limited Partnership 2014).

30 This is estimated based on the fact that The Pembina Institute's (2013) estimate of 24 mtpa in LNG exports is equivalent to 3.12 Bcf/day (see Conversions Used in this Report at the beginning of this document). FNFN LNG-induced gas extraction calculated in the Phase 1 report is estimated to be between 16 and 92 percent of this amount of LNG feedstock. The author multiplied 16.5 million tonnes of CO^2e by 16 and 92 per cent respectively to come up with an FNFN gas upstream CO^2e contribution of between 2.6 and 15.1 million tonnes per annum.

to somewhere between 2.1 and 10 million tonnes per year, and that by 2040, those numbers may peak at between 6 and 15 million tonnes per year. Keep in mind this is only formation CO_2 removed from the gas, not the GHG emissions associated with activities to explore for, develop facilities to extract, refine, process and then liquefy the natural gas.

5.2 POTENTIAL SOCIAL, ECONOMIC AND CULTURAL EFFECTS ON FIRST NATIONS

Gas sector activity can have beneficial or adverse effects on different aspects of the human environment. While the magnitude of potential effects depends on the scale of actual activity and the way in which effects are monitored and managed, some general comments on likely change can be provided based on case studies, academic research and the author's professional experience.

First off, there is the potential for extensive beneficial economic effects on the people of the Fort Nelson region from expansion of gas related activities associated with the B.C. LNG sector. For those able to take advantage, employment in the gas sector can provide high paying jobs with training toward transferable skills. It can generate local and regional business development opportunities. Increased training opportunities for local and regional youth may increase employability into the medium-scale future and reduce out-migration pressures on local job seekers. Some amount of regional and local economic diversification would likely occur over the short to medium-term, with more demand for goods and services. It is also possible that spin off effects may increase demand for goods and services in priority activities for FNFN such as tourism[31]. In-community infrastructure improvements would also likely occur.

Currently, FNFN and its members have fundamental limits to their ability to take advantage of this economic growth. Most important is their small population and limited excess labour force with the required skills to engage in many of the specialized skilled job opportunities that would become available. Much of the work involved in gas exploration and development is specialized, skilled, and conducted by a small number of large, southern Canadian based companies. Increased government- and industry-sponsored training opportunities could reduce economic "leakage" out of the region, but would need to be implemented prior to, rather than during, an intensive boom period, in order to reap substantial benefits for FNFN members. To date there has been an inability in many cases for northerners, especially Aboriginal people, to take advantage of gas sector opportunities due to a lack of training and educational attainment, barriers to making Aboriginal businesses competitive with non-Aboriginal businesses specialized in the gas sector, and barriers to Aboriginal employment, among other factors.

31 Although if the wilderness character of FNFN territory is further damaged by gas activities, this could have longer term negative implications for tourism potential.

Gas development brings potential socio-economic and cultural risks as well. These can include local and regional inflation, boom and bust effects[32], and creation of tiers within local society based on socio-economic status, among other concerns. Rapid economic change can alter the fabric of northern Aboriginal communities (Angell and Parkins: 2011). In addition, there may be an increased number of local community members working away from the community for longer periods of time, which can put pressures on caregivers and spouses. Increased money in the community can change the priorities and attitudes of youth and working age population alike. Outmigration to larger centres which offer a greater mix of goods and services to spend increased disposable income on is also a risk for a remote community like Fort Nelson.

Increased income can lead to local inflationary pressures. While these can be managed by people deeply involved in the expanded wage economy, they are not so readily absorbed by those who are not. First Nations members who remain more active in the bush economy, as well as community-based workers (especially in lower paid service sectors), unemployed residents, and elders, could be more negatively affected by increased costs of living. In addition, high paying jobs outside the community can lead to a 'brain drain', with those workers most vital to the maintenance of basic goods and services in the community attracted away by higher paying jobs in industry.

Increased jobs and wages have also been shown in some studies to be related to adverse effects on the traditional Aboriginal subsistence and mixed economy. Studies have found that:

- Rotational employment caused shortages in bush food (O'Faircheallaigh: 1995);
- Aboriginal males reduced their engagement in the traditional sector as their wage employment and skills training increased (Stabler & Howe: 1990);
- Tensions can arise in the community between people engaged in the traditional and wage sectors (MacEachern: 1983); and
- Close proximity to roads, influx of non-aboriginal people, and high personal income are all associated with lower community harvest levels (Wolfe & Walker: 1987).

Thus, while higher income and more jobs and skills are attractive, there are also aspects of living in an overly wage economy-focused community often unattractive to First Nations. These may include:

- Poorer diet (more store bought and less country food);
- Less active people and associated health effects;
- Less time spent on the land;
- Higher alcohol and drug use;
- The younger generation losing its Aboriginal language;

32 Year-to-year fluctuations in income in Fort Liard, NWT, directly north of FNFN territory, are an example of this "boom and bust" phenomenon. Average personal income grew by 16.1% in Fort Liard from 1998 to 1999 alone, largely related to oil and gas work. Subsequent average income growth has been muted, with cumulative economic growth between 1999 and 2006 in Fort Liard limited to 11.6%, three times lower than the NWT average of 35.5% (NWT Bureau of Statistics: 2010). In fact, the years 2004 and 2006 both saw average income actually fall in Fort Liard, and with these downturns in the economy came increasing unemployment and social assistance beneficiary numbers. This illustrates the high potential for boom and bust fluctuations in overly gas dependent communities.

- Reduced youth-elder interactions and losing Dene values and traditional knowledge;
- Higher stress among leadership and Band staff in the face of development pressures; and
- Uncertainty about the future leading to social distress.

Longer-term sustainability of gas development is also a consideration. As a non-renewable resource within a confined geographic area, the upstream gas extraction sector is by definition not a sustainable long-term economic activity. It is likely gas activities would happen within a +/-30 to 50 year window. Once the sector begins to wind down, associated income and employment can end abruptly, resulting in the previously mentioned "bust" effects.

A combination of real and perceived environmental risks can also have adverse social and cultural impacts on Aboriginal people who still rely on the land for part of their livelihood and for the meaningful practice of their culture. FNFN members have already reported observations and perceptions that portions of their traditional territory in the three shale gas basins have already been polluted by gas sector activities (e.g., FNFN 2012a, 2012b, and 2013). These concerns have been expressed based on traditional knowledge observations of effects of past and present developments on water quality, animal habitat quality and animal health. The general outcome is that many FNFN members feel alienated from increasingly large portions of their traditional territory and have and may continue to become increasingly reluctant to hunt, fish and trap on the land. Among the reported concerns:

- Increased noise, light and visual, smell and tactile disturbances in the areas in and around physical works and activities, disturbing and affecting the population health of wildlife and disturbing and creating additional alienation from territory — with a variety of demonstrable negative health and well-being effects — of FNFN members;
- Increased access to and use of FNFN territory by non-Aboriginal recreationalists and harvesters, increasing competition for increasingly scarce resources and reducing FNFN enjoyment of its traditional lands and waters;
- Decreased safety (and sense of safety) for FNFN land users, including from harvesting competition, traffic issues, exposure to contamination in air, plants, wildlife and water; and
- Increasing psycho-social impact outcomes for FNFN land users who are facing these rapid and seemingly uncontrolled/uncontrollable changes, losing connection to their traditional lands, knowledge, and way of life, and increasing exposure to socio-economic marginalization and risk in their home community and Fort Nelson.

LNG-induced gas extraction will not occur in a social, economic and cultural vacuum. Additional effects loading will be layered on top of these existing effects on First Nations people, who are often the most sensitive receptors of change to the human environment.

5.3 SUMMARY OF POTENTIAL IMPACTS ON FNFN TERRITORY FROM LNG-INDUCED GAS EXTRACTION

Table 12 identifies how some of the required physical works and activities of the upstream gas sector required in an LNG future may interact with valued components of the biophysical and human environment in FNFN territory, creating new and exacerbating existing effects.

The likely adverse impact outcomes of LNG-induced demand on FNFN territory include (see Section 3.2 for additional discussion on some of the likely effects types):

- Reduced forested area in FNFN territory, increased forest loss and fragmentation of forest ecotypes, high degree of edge effects on forests, associated vegetation and wildlife species reliant upon forest environments;
- Opening up of new, relatively untouched areas in FNFN territory (e.g., portions of the Liard Basin) by roads and pipelines, in particular, reducing their wilderness, ecological and Aboriginal rights practice values;
- Loss or contamination of rare and culturally important plants and ecotypes/habitats;
- Reduced amount of — and functionality of — wetland complexes, critical for moose and other ungulates, furbearers, birds, and fish and other aquatic species harvested by FNFN members, and for the proper functioning of the hydrologic system upon which FNFN relies;
- Reduced water quality and quantity and reduced riparian habitat vitality, with attendant risks for aquatic and terrestrial species;
- Disturbance of aquatic and riparian habitat critical to fish and other aquatic species, especially via increased water withdrawals, water contamination, erosion due to pipeline water crossings and road building;
- Increased predation of key ungulate species like moose and woodland caribou, a Species at Risk, especially in relation to long linear developments;
- Introduction of invasive species and displacement of native ones (wildlife and vegetation);
- Increasing dust and soil erosion, associated with adverse air, water, traditional use and vegetation effects;
- Large increases in GHG emissions, contributing to climate change;
- Increased electrical power and equipment requirements, inducing additional development and causing a variety of disturbances and risks;
- Increased noise, light and visual, smell and tactile disturbances in the areas in and around physical works and activities, disturbing and affecting the population health of wildlife and disturbing and creating additional alienation from territory — with a variety of demonstrable negative health and well-being effects — of FNFN members;

Table 12: Upstream Gas Industry Component — Environment Interaction Matrix

	Investigative use/ research	Well pads	Wells	Pipelines & flowlines	Roads	Seismic lines	Facilities	Gas plants	Compressor stations	Frac sands mines	Dugouts/ $H_2$0 storage	Work camps	Waste mgmt. facilities	Workforce
Increased linear and areal disturbance		x		x	x	x	x	x	x	x	x	x	x	
Increased habitat loss & fragmentation		x		x	x	x	x	x	x	x	x	x	x	
Decreased wildlife numbers and population health		x	x	x	x	x		x	x	x		x		x
Increased water usage		x	x		x					x	x	x		x
Reduced water quality		x	x		x									
Decreased local air quality		x	x		x			x	x	x			x	
Increased GHG emissions		x	x	x	x			x	x					
Increased terrestrial traffic	x	x	x	x	x	x		x		x		x		x
Increased aerial traffic	x			x		x								
Increased pressure on physical and social services					x							x		x
Increased competition for resources				x	x	x								x
Reduced enjoyment of land	x	x	x	x	x	x	x	x	x	x	x	x	x	x
Increased risk of accidents, malfunctions and contamination		x	x	x	x		x	x	x	x			x	

- Increased access to and use of FNFN territory by non-Aboriginal recreationalists and harvesters, increasing competition for increasingly scarce resources and reducing FNFN enjoyment of its traditional lands and waters;

- Decreased safety (and sense of safety) for FNFN land users, including from harvesting competition, traffic issues, exposure to contamination in air, plants, wildlife and water; and

- Increasing psycho-social impact outcomes for FNFN land users who are facing these rapid changes.

Many of these risks are well understood and have already been experienced in FNFN territory. Others are still poorly understood, as noted in a recent report by the Council of Canadian Academies (2014). It is important to remember that hydraulic fracturing at the scale at which is currently occurring in shale deposits, and the increasing scale at which it is proposed in the future in FNFN territory, is still in its infancy. Many jurisdictions have reacted to this fact with caution, not allowing hydraulic fracturing until further research on water quantity and quality, radioactivity and seismic activity issues, among other question marks, are dealt with (e.g., Quebec). In other jurisdictions like New Brunswick, First Nations and other people have reacted with alarm to the proposition of use of this technology. Questions about the legacy effects for further generations of un-estimable future impact loads are top of mind for FNFN members and leaders. Further research is critical to understand short-, medium- and long-term effects of hydraulic fracturing and all the other physical works and activities required to produce from unconventional gas deposits.

Overall, many species will be at greater risk from the increased number of physical works and activities required on FNFN territory as a result of LNG-induced demand. They include but are not limited to:

- Woodland caribou (a preferred harvesting species at risk of extirpation at the regional level);

- Moose (a critical preferred harvesting species already subject to declining numbers and population health, according to FNFN (2012b));

- Beaver, among other furbearers, at risk from human interactions; deforestation, wetland, lake and river impacts, among other factors;

- Many bird species, including species at risk and harvested/culturally revered species;

- A variety of fish species; and

- Human beings. FNFN members in particular have already reported increased land and water alienation, loss of faith in country food sources and associated reduction in country food production, consumption and sharing, reduced ability to meaningfully travel and harvest from the land, reduced enjoyment of traditional territory, reduced opportunities for inter-generational knowledge transfer, an inability or unwillingness to drink water from previously safe locations on the land, and an overarching sense of psycho-social loss and despair associated with these and other losses and their inability to control their own social, economic and cultural futures.[33]

33 These issues are noted in many environmental assessment submissions (e.g., FNFN 2012b; FNFN 2013), the FNFN Strategic Land Use Plan (FNFN 2012a), and in many presentations and other outreach efforts by FNFN Chief and Lands Department (e.g., Lowe and Tate 2013; Gale 2013).

FNFN territory has several unique characteristics that change the likely level of effects from LNG-induced demand; some for the better and some for the worse. On the positive side of the ledger:

1. FNFN gas deposits contain a great deal of gas per section of land, and with that comes high EURs that allow for fewer wells to generate an equivalent amount of gas as other WCSB gas deposits; and

2. Despite being a relatively undeveloped play, the Horn River Basin in particular, and to a lesser degree the Cordova Embayment and Liard Basin, do have some infrastructure in place that will reduce the amount of additional linear and areal disturbance required to the landscape versus an entirely new exploration location.

On the negative side of the ledger:

1. FNFN territory shale deposits have very high CO_2 content, meaning their potential contribution to GHG emissions (and thereby climate change) is much higher per unit of production than other WCSB basins, especially if current B.C. policy to allow CO_2 to be directly vented to the atmosphere at gas plants continues. The difference may be a factor of as much as 6:1 versus other deposits;

2. FNFN territory fracking inputs requirements, in terms of water, sand and chemical inputs, have proven to be much higher than those for other unconventional deposits in the WCSB or indeed anywhere in North America. Measured on a per well basis, for example, Horn River wells require more than ten times as much water as Montney wells; and

3. Despite having some infrastructure in place, FNFN territory is still farther from the LNG export facilities and will likely require large increases in major infrastructure projects like gas plants and sales gas pipelines to the south. These large projects tend to be more invasive than smaller projects and facilities.

SECTION 6

Summary, Implications and Recommendations

6.1 SUMMARY OF PHASE 1 AND PHASE 2 FINDINGS

Total gas extraction from FNFN territory will increase as a result of LNG export sector requirements by somewhere between almost tripling and a nearly ten-fold increase, to between 0.77 and 2.96 Bcf/day.

Phase 1: B.C. LNG Export-induced Gas Extraction Scenarios for FNFN Territory

Phase 1 developed the following scenarios as to how much LNG-induced gas extraction will occur in FNFN territory:

1. B.C. LNG exports will average between 37.5 and 82 mtpa, starting about 2018, and lasting over an initial 20 year period (this study has not estimated the lifetime of the B.C. LNG sector).
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 likely induce between 490 million and 2.68 billion cubic feet per day in gas extraction from shale gas basins in FNFN territory over the 20 year time frame.

The scenarios developed indicate that the creation of a B.C. LNG export sector will stimulate/induce more gas extraction from FNFN territory. In 2012 production LNG production within the FNFN territory was 0.28 Bcf/day. Total gas extraction from FNFN territory will increase as a result of LNG export sector requirements by somewhere between almost tripling and a nearly ten-fold increase, to between 0.77 and 2.96 Bcf/day.

Phase 2: Modelling Effects of LNG-induced Gas Extraction on FNFN Territory

LNG-driven shale gas extraction of between 0.49 Mmcf/day and 2.68 Bcf/day could result in the following changes in the three FNFN territory shale basins during the first 20 years of the sector:

- Between 356 and 3,995 new hydraulically fractured shale gas wells;
- Development of between 30 and 333 new large industrial facilities in the form of multi-well pad complexes, each covering an average area of nine hectares;
- Between 1440 and almost 16,000 km of new seismic lines;
- Between 150 and 1,665 km of new roads;
- Development of between 135 and as much as 3,333 km of new pipeline ROW, including major sales gas pipelines to overcome current transportation capacity constraints;
- Generation of a total of between 1,635 and 20,900 km of new linear disturbance;
- Generation of total direct areal disturbance of between 30 and 375 km^2, along with an additional Zone of Influence some 2.41 times greater, for a total impact footprint of between 104 and 1,277 km^2;
- Between one and five additional large 600 Mmcf/day or greater throughput sales gas plants, and dozens to hundreds of other "facilities" in support of gas refining and transportation;
- Additional GHG emissions of between 2.6 and 15.1 million tonnes per annum, or between 6 and 34.7 per cent of B.C.'s legislated emissions target level for 2020 of 43.5 million tonnes CO_2e;
- Water usage in the hydraulic fracturing process alone of between 11 and 320 billion litres of water (between 31 and 80 million litres per well);
- Construction of between 60 and 666 water storage pits/dugouts;
- Use of 1.4 to 16 million tonnes of frac sands, and mining of a substantial amount of it from FNFN territory;
- Use of 55 million to 1.6 billion litres of chemical additives in hydraulic fracturing processes; and
- Development of between 534 and almost 6,000 borrow sites and between 90 and almost 1,000 waste disposal sites, among other requirements.

LNG-driven shale gas extraction of between 0.49 Mmcf/day and 2.68 Bcf/day could result in a total impact footprint of between 104 and 1,277 km^2.

6.2 IMPLICATIONS OF LNG-INDUCED GAS EXTRACTION FOR FNFN TERRITORY

Gillis (2014) notes that the four NEB export licences approved in December 2013 alone "were the equivalent of almost 2 million barrels of oil per day for 25 years. In other words, roughly four times bigger than the proposed Enbridge pipeline and the same size of the entire Alberta Tar Sands oil output today."

There has been much recent attention paid to the development of large-scale LNG export facilities on Canada's west coast, and to a lesser degree the impact of those facilities on aboriginal peoples. Concerns have also been raised regarding several gas pipelines of unprecedented size proposed to move gas from northeast B.C. to these facilities. At the same time, there has been little discussion of the upstream impacts that LNG export would have on aboriginal peoples from whose territory the natural gas to be exported is to be extracted, where there would be a dramatic increase in natural gas production that would be required to meet the demands of the proposed LNG facilities.

There is strong potential for increase hydraulic fracturing (fracking) activities as a result of the proposed massive growth in gas development due to the burgeoning BC LNG export sector. The analysis presented in this study clearly indicates that the scope of development required to explore, capture, and produce natural gas to feed export facilities and proposed pipelines in B.C., and to meet the stated goals of the Province's *LNG Strategy*, is likely to have significant impacts on FNFN territory.

Issues that are not confined to specific locations include large increases in GHG emissions, which will contribute to global climate change and will reduce B.C.'s ability to meet its legislated GHG emission reduction targets, and rapidly increasing water usage, which can have widely distributed effects and implications across a variety of VCs, including water quality and quantity itself, but also navigation, wildlife health, fish health, vegetation, and riparian and terrestrial habitat quality.

While this study does not estimate where within FNFN's three shale gas basins additional gas sector activities will be located, a couple of location- or area-specific issues are worthy of note:

1. Given their high levels of reserves and high production rates per well, it is likely that induced demand from natural gas markets will see both increased production and construction in Horn River and exponentially increased exploration, development and production in the Liard Basin. For large portions of the Horn River Basin, the most intensively industrialized FNFN shale gas play to date, a major concern will be cumulative effects on an already increasingly disturbed and fragmented ecosystem. For example, rising water withdrawals, rising pressures on woodland caribou core habitat (Ungulate Winter Range and Core ranges), and increased land alienation for FNFN harvesters may be reaching or have exceeded 'tipping points' already. This could be made worse by any additional development of the Horn River Basin.

2. Despite being less developed to date, the Liard Basin has shale gas potential labelled "world class" (Apache Corporation 2012). Pressures on it from LNG-induced demand may be very strong.

3. A variety of areas with woodland caribou core habitat are already at risk from high intensity of linear and areal disturbance from gas sector activities. Without meaningful change to the way woodland caribou are protected — and soon — regional extirpation from many core areas is possible and will

primarily be linked to the effects of the gas sector. Given that woodland caribou is both *SARA*-listed and a preferred harvesting species for FNFN, there is a high degree of urgency required in planning a sustainable future for this species. Any increase in habitat fragmentation may have irrevocable effects on this sensitive species. This is a species-specific reminder that LNG-induced gas extraction from FNFN territory is not occurring on a blank ecological slate, but rather in a sensitive receiving environment already subject to extensive adverse cumulative effects loading, much of it related to the natural gas sector.

Overall, better planning is required to protect portions, in particular, of the Horn River and Liard Basins. Areas of heightened requirements for protection within these basins from the FNFN (2012a) *Strategic Land Use Plan* are identified in Figure 14.[34] To date, of these areas only Maxhamish Lake has any meaningful land use protection in place.

6.3 RECOMMENDED FURTHER RESEARCH

This study, like the fledgling B.C. LNG export sector itself, is preliminary and exploratory in nature. It represents an important first step in establishing the range of potential scenarios for LNG extraction on FNFN lands — and an important starting point for a serious dialogue about upstream environmental impacts of B.C.'s LNG export market ambitions. To the author's knowledge, the scenarios developed are the first effort by any party to identify these upstream implications in specific First Nations territories. They are realistic within the confines of currently available public data. The author welcomes other parties to put forward additional data into the public realm, to assist in refining this critical futuring exercise. Regardless of which scenario comes to fruition, it is incumbent on affected First Nations like FNFN, industry and responsible government authorities to both inform additional refinement of these scenarios and to plan for and confront their implications in advance. Only then can the parties be ready to deal with them decisively and meaningfully, when one of them plays out in reality. This is the true value of any such scenarios exercise.

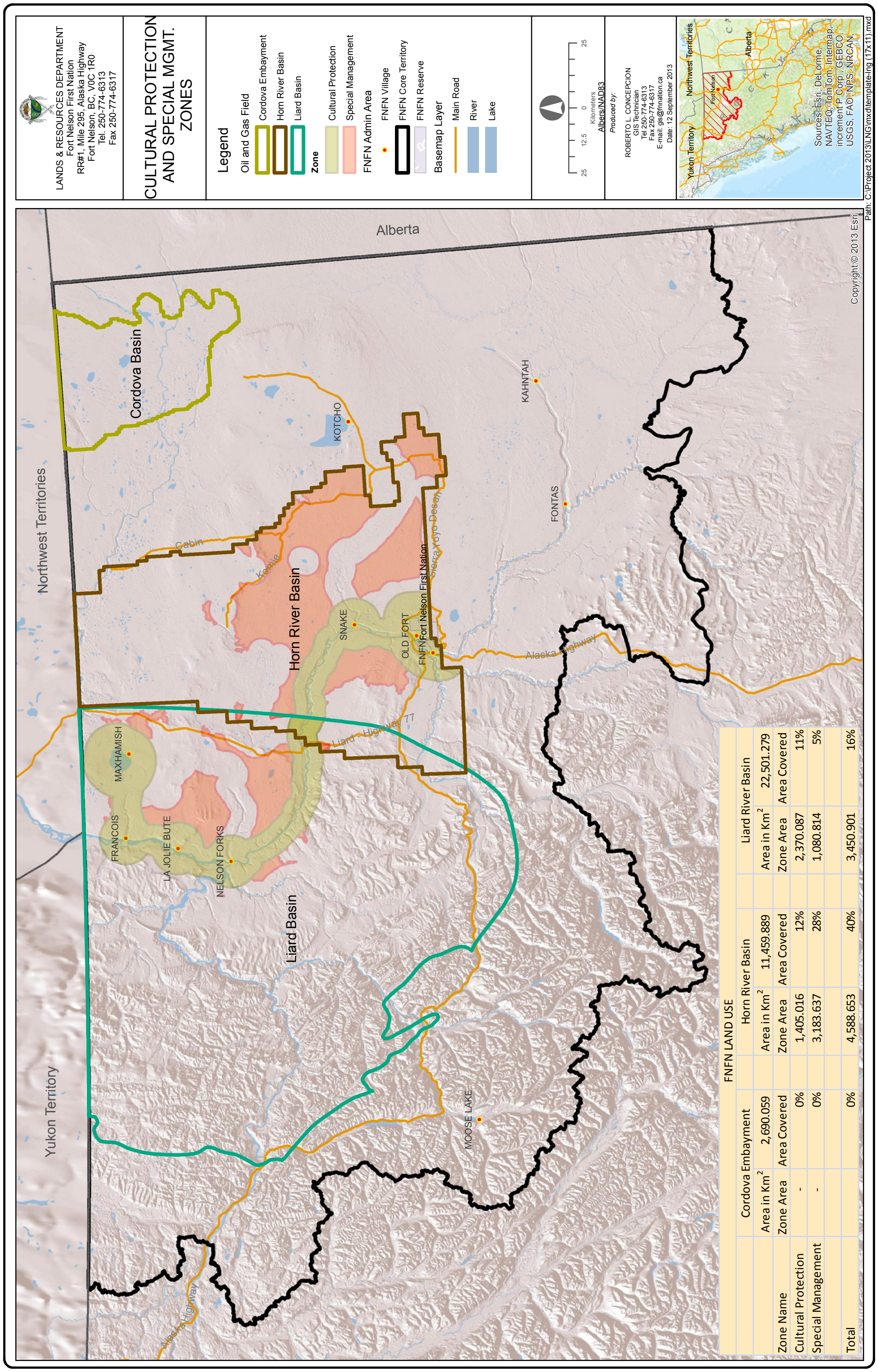
More study of LNG export and gas production issues is required. B.C. has world class aspirations for its LNG sector. World class planning, cumulative effects assessment, monitoring and adaptive management would also seem to be called for. The following are some areas where gaps in the research record need to be filled.

- **RESEARCH RECOMMENDATION #1:** Additional scenario modeling exercises. 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. See for example recommendation by Duinker and Greig (2007) and Greig and Duinker (2007).

- **RESEARCH RECOMMENDATION #2:** Water studies to establish an Aboriginal base flow regime. For an example, see *As the Rivers Flow: Athabasca River Knowledge, Use and Change (*Candler et al. 2010). That study, in the context of the similarly water-intensive oil sands mining industry and the

34 In Figure 14, locations of two of the types of heightened protection zones in the FNFN *Strategic Land Use Plan* are identified for each of the three shale gas basins (in fact, there are none of them in the Cordova Embayment). Cultural Protection Zones are the highest value locations in FNFN territory for traditional use, occupancy and biophysical values. Any industrial activity within them is discouraged and subject to extremely high levels of monitoring and control. Special Management Zones are also high value locations where industrial activity is subject to strict controls.

Figure 14: FNFN Cultural Protection and Special Management Zones within Shale Basins



FNFN LAND USE

Zone Name	Cordova Embayment Zone Area	Cordova Embayment Area Covered	Horn River Basin Zone Area	Horn River Basin Area Covered	Liard River Basin Zone Area	Liard River Basin Area Covered
Area in Km²	2,690.059		11,459.889		22,501.279	
Cultural Protection	-	0%	1,405.016	12%	2,370.087	11%
Special Management	-	0%	3,183.637	28%	1,080.814	5%
Total		0%	4,588.653	40%	3,450.901	16%

similarly high Aboriginal traditional use values of northern Alberta, developed thresholds of minimum required water levels for First Nation members to access their traditional territories and practice Treaty rights on water (Aboriginal Base Flow), offering a way to translate Treaty rights and cultural needs into a format that can inform policy and project decision-making.

- **RESEARCH RECOMMENDATION #3:** Additional research on the effects of hydraulic fracturing on water quality in FNFN territory. The conduct and effective communication of water quality research, especially in relation to the risk of resurfacing, risks to ground water resources, qualitative and quantitative measures of effects on wetlands of the gas sector, and water risk perception and communication studies, is a major existing gap in research and outreach to First Nations peoples.
- **RESEARCH RECOMMENDATION #4:** Traditional use alienation studies. This would include community-integrated assessment work to identify areas on traditional territory that have already been or are moving towards being alienated from traditional use due to physical works and activities making them off limits, or observed instances and psycho-social concerns about contamination rendering them off limits to would-be harvesters.
- **RESEARCH RECOMMENDATION #5:** Country food production and consumption studies, which would establish the importance of different locations and types of country food in FNFN territory, identify changes over time in reliance on areas and food types, and characterize effects of same;
- **RESEARCH RECOMMENDATION #6:** Gas sector impact footprint studies, to more fulsomely establish impact footprints for different types of gas industry activities in northeastern B.C. and specifically in FNFN territory. This needs to go beyond the current physical footprint focus of work being conducted by the Province and the B.C. OGC (2013a). This may include developing metrics such as average patch size, fragmentation, and interior forest dimension, and estimating using both Western science and First Nations traditional knowledge the extent of edge effects and establishment of reasonable Zones of Influence — effects on wildlife, plants, other biophysical Valued Components, beyond the strict extent of the feature itself — for a variety of gas sector physical works and activities.
- **RESEARCH RECOMMENDATION #7:** Effects of Large Industrial Complexes. Closely related to research recommendation #6 is more research into the effects of the large industrial complexes that multi-well pads are becoming. While multi-wells per pad technologies are likely to decrease the overall number of clearings required on FNFN territory per unit of production, they will also increase the number of large industrial facility sites on FNFN territory, likely exponentially. Whether this growth in the number of major industrial facilities is more or less impactful than a larger number of smaller sites remains open to debate and requires further study. Because they are much larger than conventional well pads, and involve more intensive on-site activity and process inputs and outputs, these facilities may have substantially different effects on the environment than traditional well pad complexes in ways currently poorly understood.
- **RESEARCH RECOMMENDATION #8:** Moose population studies, to quantify FNFN-observed declines in population health status of this preferred and heavily relied upon species.
- **RESEARCH RECOMMENDATION #9:** Additional woodland caribou gas sector impact research, especially in relation to speeding up and putting adequate resources to research into herd population and health status in gas affected areas, and establishing appropriate thresholds of acceptable linear disturbance beyond which industrial development will not be allowed.

6.4 POLICY RECOMMENDATIONS

Policy Recommendations Related to Assessing LNG as an Integrated Production System

> *"An individual gas well project in the Northeast [of B.C.] may have small impacts — but a thousand new gas wells can transform an ecosystem" — Environmental Law Centre (2013, 18).*
>
> *"Premier Clark attempted to back out of her original promise to have high environmental standards for the entire LNG industry by saying the commitment only applies to liquefaction facilities themselves. In response, we argue that the impacts from any plants in Prince Rupert and Kitimat would be just the tip of the iceberg. The full picture of impacts from LNG includes the pipelines, processing plants and gas wells needed to feed these liquefaction facilities" — Horne (2013).*

No work estimating the potential cumulative environmental costs of developing a B.C. LNG export sector has been completed to date by government or industry. As a result, it will be difficult, if not impossible, for British Columbians, First Nations and government to weigh the costs and benefits of LNG upstream expansion of the natural gas sector in B.C.

Currently, regulatory approvals for new oil and gas extraction facilities are being done on an incremental basis, with inadequate consideration of existing and cumulative effects of additional development on the environment. In addition, the B.C. government is thus moving ahead with developing infrastructure for an LNG export sector without a full consideration of the potential environmental impacts on the areas that will be required to feed these export facilities. Though pipeline projects and LNG facilities are currently considered separately by environmental assessment bodies, an LNG plant cannot exist without a dedicated pipeline. Likewise, the pipeline is of no purpose without either the LNG facility to feed or the upstream gas production infrastructure to fill the pipe. LNG requires an integrated production system. As such, it is irresponsible to consider the development of any part of the production system (i.e., the export facilities or pipelines) without considering the associated development that is required within all parts of the production system (i.e., the extraction of natural gas from the ground, with all its attendant effects). As noted by the Environmental Law Centre at the University of Victoria (2013, 4):

> *"Government — and the public — are responding ad hoc to each individual [LNG] proposal as it is filed. No environmental assessments will be done on the thousands of gas wells [required in northeast B.C.]."*

One of the implications of this study is that artificially separating the liquefaction and pipeline portions of the LNG production system from the original source of the gas is to ignore some of the largest effects of this new industry of the well-being, way of life and rights of First Nations in the path of change.

The author provides the following policy recommendations regarding treating LNG as an integrated production system when planning an LNG future:

- **POLICY RECOMMENDATION #1:** Before LNG is developed in B.C., proper strategic and cumulative effects assessments, planning and consultation be undertaken. The author is certainly not the first to call for more effective and more urgent cumulative effects assessment of the upstream gas sector in northeastern B.C. and/or the development of a B.C. LNG export sector. In August 2013, the Environmental Law Centre (2013) at the University of Victoria called for the B.C Minister of Environment to order a Strategic Economic and Environmental Assessment of B.C. LNG development, as allowed under Section 49 of the *B.C. Environmental Assessment Act*.[35] B.C.'s Select Standing Committee on Finance and Government Services (B.C. Government 2013, 19) recently echoed this final recommendation, calling for the Province to "consider a strategic, cumulative environmental assessment of LNG projects in northwest B.C. and the creation of a common energy corridor for successful projects."

- **POLICY RECOMMENDATION #2:** Development of a multi-project Working Group with seats for all affected first Nations, to strategically assess the best way to create and manage a sustainable LNG export production system. This echoes calls by other First Nations for strategic assessment of this burgeoning sector,[36] as well as those of NGOs such as The Pembina Institute (Horne 2013) and the Northwest Institute for Bioregional Research (Environmental Law Centre 2013).

- **POLICY RECOMMENDATION #3:** Inclusion of scenario analyses of upstream effects in the environmental assessments for all proposed LNG facilities and pipelines.

Other Policy Recommendations

- **POLICY RECOMMENDATION #4:** Development of a more meaningful Cumulative Effects Assessment Framework in FNFN territory to understand appropriately the existing level of impacts on water, lands, air, wildlife and Treaty rights in FNFN territory prior to making irrevocable decisions that may further impact on these VCs. Canada, British Columbia and FNFN should work together to develop an appropriate, VC-focused, cumulative effects assessment, monitoring and adaptive management regime for FNFN territory. FNFN has previously argued for a regional cumulative effects assessment to build a foundation against which thresholds of manageable change can be estimated, and against which future Projects can be assessed (e.g., FNFN 2013).

- **POLICY RECOMMENDATION #5:** Establish a landscape approach to energy permitting (Johnson et al. 2010), including meaningful and enforced linear disturbance and fragmentation thresholds that identify maximum allowable activity levels within gas producing areas of heightened Aboriginal value and ecological sensitivity.[37]

35 Environmental Law Centre (2013) in the same submission requested a similar request for the federal Minister of the Environment to develop a joint committee with the Province to conduct a regional study of the effects of LNG development in northern British Columbia, pursuant to Section 74 of the *Canadian Environmental Assessment Act.* Neither request has been adhered to at the time of writing of this report.

36 See the results of the First Nations LNG Summit held in October, 2013, in Prince George, at http://fnlngstrategy.ca/.

37 Land use thresholds for road density, total linear density, habitat, core areas (large non-fragmented forests), stream crossings, and water usage are a few examples.

6.5 CLOSURE

"Liquidating BC's gas resources as quickly as possible is not a sustainable energy plan." (Hughes 2014, 18)

Effects of gas sector activities are having demonstrable cumulative impacts on FNFN territory in the Horn River Basin, and increasingly in the Liard Basin and Cordova Embayment as well. B.C.'s *LNG Strategy* could see the number of shale gas wells drilled in these shale gas basins in FNFN territory increase by between 350 and almost 4000 wells. All of the new wells will likely use hydraulic fracturing technology, which has extremely high water, chemical and other additive input requirements. In addition, the high carbon dioxide content in FNFN shale gas basins will create high potential for increased contributions to climate change, and a substantial challenge to B.C. meeting its legislated GHG emissions reduction targets.

This study has attempted to identify how much change LNG will bring, focusing only on the first 20 years of what would likely be a much longer-lived LNG export sector, and using a series of conservative assumptions that likely underestimate the amount of change to be expected in both the Low Growth and High Growth LNG-induced gas extraction scenarios for FNFN shale basins.

Due to its relative development complexity, long distance and high costs to date, development of FNFN shale deposits has lagged behind that in other B.C. unconventional gas basins, especially in the Montney. The number of wells drilled and industrial complexes developed in FNFN territory remains relatively low by comparison. Particularly in the Liard Basin, there is still time to change the way planning and development occurs, hopefully before irrevocable change to the biophysical and cultural landscape.

In closing, it is important to note that the study represents only a first exploratory step. It is intended as a starting point for further discussions. The findings are 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. They will also hopefully open the eyes of others — other affected First Nations, the people of B.C., industry and the federal and provincial governments — to the fact that the domestic LNG export sector <u>ends, but does not begin</u>, on the B.C. Coast, and that upstream impacts must be taken into consideration during planning.

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