Evaluating British Columbia's economic policies for liquefied natural gas development

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Abstract

British Columbia is attempting to develop a large-scale liquefied natural gas (LNG) sector to export natural gas to Asia, with capital investments estimated to be as high as $40 billion for a single LNG plant. An alleged benefit of LNG development is increased revenue for the BC provincial government of over $27 billion. Our research investigates potential fiscal benefits for BC from LNG and the processes that were followed when developing the new LNG-related economic policies. Research methods include an analysis of relevant documents, interviews with key actors, and quantitative modeling of LNG revenue impacts. Results show that the primary objective of the fiscal mechanisms is to ensure that the LNG industry is developed in BC and maximizing the return to government is a secondary objective. Secondly, the process of developing the LNG policies did not follow best practices from a public policy perspective. Thirdly, the government's projected incremental revenue from an LNG export industry is significantly exaggerated.

Keywords: LNG; Resource Development; British Columbia; Economic Policy; Fiscal Regime; Royalty; Natural Gas; Woodfibre LNG

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List of Acronyms

CCA	Capital cost allowance
CIT	Corporate income tax
GHG	Greenhouse gas
IRR	Internal rate of return
LTRA	Long-term royalty agreement
LNG	Liquified natural gas
LNGIT	LNG income tax
NPV	Net present value
PST	Provincial sales tax

Chapter 1. Introduction

British Columbia is well known for its relative abundance of natural resources that support industries including forestry, mining, fisheries, oil, and natural gas. Historically, BC's natural resource industries have exported predominantly raw products to jurisdictions with more advanced manufacturing sectors (Gunton, 2003; Halseth et al., 2014). For example, in 2017 BC generated more than double the revenue from softwood lumber exports compared to all other wood products combined (BC Stats, 2018). Although many industries have shown great revenue-generating potential, they have been prone to boom-bust cycles that have led to economic and employment issues within the province (Gunton, 2003; Halseth et al., 2014). In BC, natural resource management falls within the jurisdiction of the provincial government and most natural resources in BC are publicly owned by the residents of the province (Constitution Act, 1867, s 92A). Natural resource development in BC generates revenue for the provincial government through fiscal mechanisms such as royalties and taxes, which are then used to provide benefits to the public through various means including services, decreased tax rates, and improved or new infrastructure (Markey & Heisler, 2011).

One method of extracting financial benefit from natural resource industries is through natural resource fiscal mechanisms, such as royalties and taxes (Segal, 2010; Land, 2009; Tilton, 2004). Royalties are payments for in situ natural resources (Alberta Department of Energy, 2007; IMF, 2012). Taxes, on the other hand, are applied to many types of activities and sectors to help pay for general government expenses such as the provision of additional healthcare facilities (e.g. clinics and hospitals) and schools (Alberta Department of Energy, 2007). In BC, natural resources are publicly owned and private companies that extract and sell natural resource must pay royalties and taxes to the provincial government (Gunton, 2004; Segal, 2010). The collection of relevant royalties and taxes that are applied to an extractive industry is referred to as a fiscal system, or fiscal regime (Alberta Department of Energy, 2007; IMF, 2012). The structure of the fiscal regime; such as the applicable rate, potential deductions, and the timeline of the payments; often depends on the particular resource industry. Ideally, the fiscal regime allows the company extracting the resource to make sufficient returns to justify their investment, as well as provide sufficient economic benefits to the residents of the province (IMF, 2012; Land, 2007; Lee, 2014).

The BC provincial government has endorsed the development of a liquefied natural gas (LNG) industry to export to Asia (Government of BC, Office of the Premier, 2018). Initially, there was interest in importing LNG to BC from Asia to take advantage of higher North American prices (Natural Resources Canada, 2017). However, interest in LNG development in BC changed from an import strategy to an export strategy when natural gas prices in Asia rose well above North America prices, creating a substantial price differential between the two regions (Melikoglu, 2014). The provincial government became very optimistic about this opportunity and promised the public a booming LNG industry consisting of at least three LNG projects up and running by 2020 (Government of BC, Office of the Premier, 2011).

In 2014, efforts to encourage industry to make investments in BC influenced the replacement of the regular natural gas royalty regime with a new LNG fiscal regime to collect revenue from the LNG industry and ensure BC would get a fair return on its natural gas resources (Government of BC, Office of the Premier, 2011). The relevant mechanisms and policies included in this new regime, which will later be discussed in further detail, are the LNG income tax (LNGIT), the provincial corporate income tax with the natural gas tax credit deduction (CIT), property tax, natural gas royalties under the long-term royalty agreement (LTRA), and the BC Hydro eDrive subsidy.

The purpose of this study is to take an in-depth look at the design, development process, and potential economic impacts of BC’s LNG-related fiscal policies and the development of LNG in BC. This is achieved through a literature review, an analysis of relevant documents, interviews with key informants that have direct knowledge of the new LNG fiscal regime, and quantitative modeling of LNG revenue impacts using the proposed Woodfibre LNG plant as a case study. In the quantitative analysis, I estimate the revenue that would be generated by the proposed Woodfibre LNG plant and directly compare the projected revenue to the revenue generated by natural gas sold to traditional markets (domestically and to the United States). This revenue comparison is just one of the relevant factors in making an informed decision as to the fiscal benefits of LNG development.

The primary research question for this study is: How will BC benefit from the newly developed LNG fiscal regime? Answering this question requires addressing four sub questions. They are as follows:

1. What are the relevant LNG economic policies that make up the fiscal regime in BC?
2. What process was followed to develop the LNG-related economic policies and overall fiscal regime?
3. What is the incremental government revenue that can be expected from the Woodfibre LNG plant as a result of the new LNG fiscal regime?
4. How does the incremental government revenue from the Woodfibre LNG plant compare to the government revenue generated by the natural gas industry under BC's current natural gas royalty regime?

By answering these questions, I seek to provide an in-depth critical evaluation of the design and process of BC's new LNG fiscal regime.

Following this section, I provide the relevant background information for my study. This includes a comprehensive review of fiscal mechanisms in general and the LNG development opportunity from a global perspective. Next, I discuss LNG development in the context of British Columbia. This includes a review of the LNG development opportunity in BC, the proposed BC projects, BC's regular natural gas royalty regime, and the economic policies that make up the new LNG fiscal regime. Following this, I outline the methodology of my study which includes a literature review, a document analysis, key informant interviews, and a quantitative analysis. Next, I state the results of my study, followed by a discussion. In the final section I state my conclusions and provide recommendations.

Chapter 2. Background

2.1. Fiscal Mechanisms

Natural resource fiscal mechanisms, including royalties and taxes, are important because they provide an economic benefit to the owners of the resource (Segal, 2010; 2012; Tilton, 2004). Royalties, one of the key fiscal mechanisms explored in this study, stem from the idea that natural resources are publicly owned and therefore belong to everyone that lives within a particular territory (Land, 2009; Markey & Heisler, 2011). These publicly owned natural resources are managed by governments on behalf of the public (Alberta Department of Energy, 2007; Otto, 2001; O'Faircheallaigh, 1999). Revenues generated from natural resource royalties and taxes can be used to benefit the public in many ways including developing public infrastructure, creating jobs, and decreasing taxes (Markey & Heisler, 2011; Segal, 2012). In some jurisdictions, such as Alaska, revenues are distributed directly to the public (Segal, 2012).

According to the Canadian Constitution, authority over the management of natural resources, including developing policies and fiscal mechanisms related to natural resources, is held by provincial governments (Constitution Act, 1867, s 92A). Historically, British Columbia has had an abundance of renewable and non-renewable natural resources. The relative abundance of natural resources has offered tremendous opportunities to generate resource revenues for BC. The Province has put many fiscal mechanisms into place to collect revenues from natural resource industries. For example, in the forestry sector the Province generates revenue from stumpage fees, logging tax, and bids on timber rights (BC Ministry of Finance, 2018).

2.2. Natural Resource Rent

An important component of economics surrounding natural resource extraction is rent: the excess revenue over the cost of producing the natural resource, including a normal return to capital (IMF, 2012; Tilton, 2004). Fiscal mechanisms, such as royalties and taxes, are designed to collect a portion of the rent and ensure fair returns to the owners of the resource (Tilton, 2004; Weijermars, 2015). The “owners” of the resource refer to the citizens that reside in a state or province, and to the state or provincial government that manages the resource on behalf of the citizens (Tilton, 2004; Weijermars, 2015). Collecting rent and generating revenue for the owners of a natural resource helps provide justification for depleting the resource and any potential impacts associated with resource extraction (IMF, 2012; Weijermars, 2015). In the case of natural gas extraction, the revenues generated by the industry are traded-off with potential environmental impacts (Lee, 2014; Melikoglu, 2014). These potential impacts include groundwater contamination and wastewater generation from the fracking process, greenhouse gas emissions caused by flaring and methane leakage, and seismic activity caused by fracking (Melikoglu, 2014). Justifying resource depletion and environmental impacts with revenue generation has become quite common in resource-rich countries and follows the theory of weak sustainability, or what is also known as the Hartwick-Solow rule: exhaustible natural resources (natural capital) can be replaced with human or financial capital, so as to not limit the ability of future generations to meet their needs (Gutés, 1996).

Extraction of these non-renewable resources should result in the owners of the resource being properly compensated with long-term wealth (Weijermars, 2015). What is deemed to be a ‘fair’ return for the owners can differ substantially and is the responsibility of the government to determine in negotiations with extractive industry operators (IMF, 2012). “Operator” refers to the private company that extracts the resource for profit, but does not technically own the resource (IMF, 2012; Weijermars, 2015). Returns to the resource owner must be a suitable amount to justify depleting a finite resource (IMF, 2012; Weijermars, 2015). In theory, the royalty can be designed to collect 100% of the rent and the project would still be profitable for the operator since a normal return on capital is included in the company’s operating costs (IMF, 2012).

2.3. Fiscal Mechanism Development

Ideally, a jurisdiction will work in the public interest and adopt fiscal mechanisms that will maximize the economic benefits of resource extraction that will accrue to the resource owners, the residents of the jurisdiction (Tilton, 2004). Achieving this, however, is a complex task for a variety of reasons. A government must first make the decision to develop a non-renewable natural resource industry, with the understanding that by doing so the government will incur an opportunity cost (Tilton, 2004). An opportunity cost, or user cost, exists when non-renewable resources are extracted and sold in the present, as opposed to saving the resources for the future (Tilton, 2004). Additionally, there are opportunity costs associated with a government developing a specific natural resource industry. Government funds allocated to that specific industry cannot be used for other governmental pursuits.

Once a jurisdiction has decided to develop a non-renewable industry, it then has the difficult responsibility of finding the optimal balance between setting the royalty or tax rate too high, and potentially discouraging private investment in the extractive industry, and setting it too low, and not collecting a fair return on the publicly owned resource for its residents in the long-term (Tilton, 2004; UN, 2016; Weijermars, 2015). Although a fiscal regime in which the resource owner collects 100% of the rent might be considered fair from the resource owner's perspective, it may not provide a strong incentive for the operator of the extractive industry (Tilton, 2004). Realistically, returns to the resource operator, including the collection of rent, must be a suitable amount to justify the substantial capital investment associated with developing the resource (IMF, 2012; Tilton, 2004; Weijermars, 2015).

One approach to finding the optimal royalty or tax rate and structure, one that results in an equitable distribution for the operator and the owner of the resource, is through a combination of modelling exercises and negotiations between the operator and the government (OECD, 2018; Tilton, 2004; Weijermars, 2015). Negotiating an equitable agreement requires both parties, the operator and the government, to have symmetric information and an accurate valuation of the resource (Weijermars, 2015). Both parties must also take price volatility into account, as making concessions in times when prices are much higher or lower than the long-term average can lead to negotiating inequitable agreements (Weijermars, 2015).

For a number of reasons, negotiating an equitable agreement is often in the interest of both the natural resource owner and operator (OECD, 2018; UN, 2016; Weijermars, 2015). First, a resource owner, represented by the provincial government in BC's case, has a fiduciary obligation to negotiate equitable and transparent agreements that build relationships and balance the interests of the resource owners and operators (OECD, 2018; UN, 2016; Weijermars, 2015). This includes consultation with First Nation governments and non-governmental stakeholders, and opportunities for public input during the fiscal regime development process to increase the level of trust and buy-in among residents of the state or province (UN, 2016). It is the responsibility of the government to perform the proper due diligence and defend against transfer-pricing scenarios, arrangements in which a private company shifts profits to a foreign country to reduce its tax burden, and opaque ownership structures that make it difficult to track profits and result in an inequitable distribution of revenues from the natural resource in the private sector's favour (IMF, 2012; Weijermars, 2015).

Second, equitable agreements can mitigate and balance the long-term business risk associated with resource extraction projects (OECD, 2018; Weijermars, 2015). Long-term risk is decreased when a stable and equitable fiscal mechanism is utilized, resulting in an accurate project appraisal presented as a net present value (NPV) (OECD, 2018; Weijermars, 2015). For industries such as mining, extraction projects have long life-cycles and the design of the fiscal mechanisms often impact the NPV calculations of the projects (Weijermars, 2015). Equitable agreements allow for the risks and benefits associated with projects to be dispersed between the resource operators and owners (OECD, 2018; Weijermars, 2015).

Third, equitable agreements can help improve the public's perception of the extractive industry and can help create public support for the resource industry (Weijermars, 2015). Questionable business practices conducted by various extractive companies throughout history have created a sense of mistrust among the public (Weijermars, 2015). It is important for private extractive companies to be transparent in their business practices and negotiate agreements in good faith (Weijermars, 2015). Additionally, it is responsibility of governments to monitor the business practices of extractive companies to ensure they comply with laws and regulations (OECD, 2018; Weijermars, 2015). Monitoring is also often completed by non-governmental organizations such as the Revenue Watch Institute and the Extractive Industries Transparency Initiative (Weijermars, 2015). If an agreement is found to be inequitable after it has been negotiated, renegotiation can be very costly for both the resource operator and owner (OECD, 2018; Weijermars, 2015).

Public input and consultation is an essential step for policy development and informed decision making (Althaus, Bridgman & Davis, 2007; European Commission, 2017; Office of the Auditor General of Manitoba, 2003). In many countries, consultation is required with all groups that would be affected by a proposed piece of legislation, as these are the groups that have stake in the success of the legislation (European Commission, 2017; Office of the Auditor General of Manitoba, 2003). Opportunities for public input should be offered at multiple stages in the policy development process (European Commission, 2017). The level and scope of the consultation may depend on the type of policy being developed (Office of the Auditor General of Manitoba, 2003). Once a certain policy option has been chosen, a crucial step is for the policymakers to inform stakeholders as to why a certain policy option has been chosen and demonstrate how it will achieve stated objectives (European Commission, 2017; Office of the Auditor General of Manitoba, 2003). This includes informing the stakeholders of all policy alternatives considered in the decision-making process (Office of the Auditor General of Manitoba, 2003).

2.4. Global context- why LNG?

Beginning in the late 2000's, there was a market shift in which the price of LNG decreased in North America and significantly increased in Asia (Melikoglu, 2014). The change in price in North America can be attributed to the development of two natural gas extraction methods that allow for extraction from shale rock (Melikoglu, 2014). The first method is hydraulic fracturing, also known as “fracking”: a method developed by Mitchell Energy & Development Corporation that uses a pressurized combination of water, chemicals, and sand to drill into rock and create fissures (Brown, 2014; Melikoglu, 2014). Upon depressurization, the gas flows out of the fissures into the well where it is then extracted. The second method is horizontal drilling: a method of drilling down vertically then, at a certain depth, drilling on an angle or horizontally (Brown, 2014). Using these two methods in conjunction has significantly increased the accessibility of “unconventional” gas reservoirs, ones that were previously inaccessible or uneconomic to extract gas from, contained within shale rock. (Melikoglu, 2014). The increase in supply led to the significant decrease in the price of LNG in North America (Melikoglu, 2014).

At the same time the price of LNG was decreasing in North America, the price in Asia was increasing due to the increasing demand, as shown in Figure 1. China, Japan, South Korea, Taiwan, and India have become the top five importers and consumers of LNG, collectively making up around 70% of the world’s import market (Shaike, Ji & Fan, 2016). There are a number of reasons for the increase in LNG demand in Asia. First, demand in Japan increased due to the earthquake that struck Japan in 2011 and caused the Fukushima nuclear disaster (Lee, 2014). Following the disaster, Japanese officials took all nuclear power facilities offline, and decided to meet the energy demand by increasing imports of LNG and other fossil fuels (Lee, 2014). Second, Asia has experienced considerable economic growth in the last decade which has increased energy demand (Shaike, Ji & Fan, 2016). Third, there has been a shift towards low-carbon energy policies in many Pacific Asian countries (Aguilera, 2014). The use of natural gas relative to other fossil fuels is believed by Pacific Asian government leaders to bring energy stability and environmental benefits to the region (Aguilera, 2014). As previously discussed, global natural gas market shifts created a significant price differential between North America and Asia, which generated significant interest in developing LNG export facilities on Canada's west coast (Melikoglu, 2014). Asia's interest in Canadian natural gas will be discussed in more detail in the following sections.

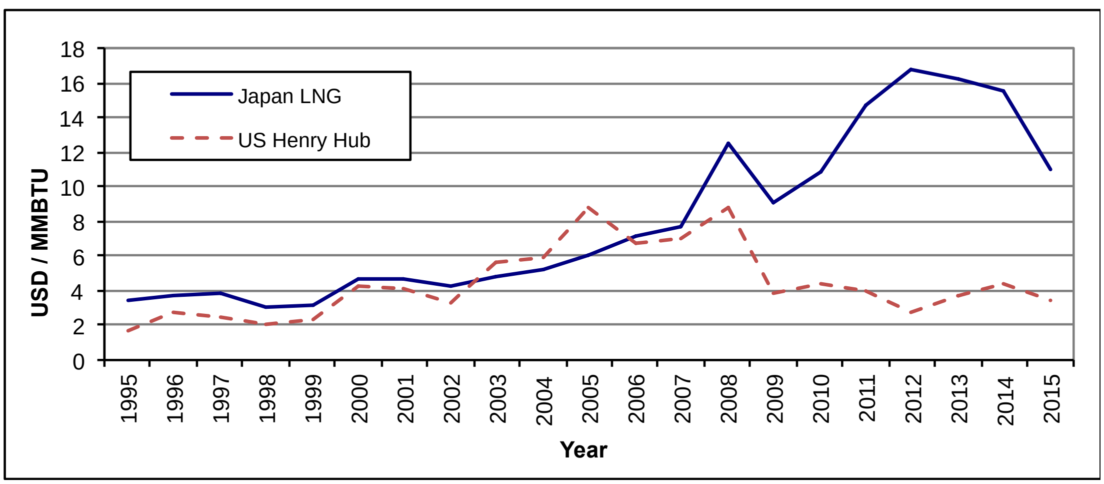

Figure 1. Graph of historical price differential between gas prices in North America and Asia. Data from BP (2016).

Chapter 3. BC LNG Case Context

3.1. LNG Opportunity in BC

The opportunity generated by the natural gas price differential between North America and Asia has led to interest in developing an LNG export industry in BC (Figure 1). As previously discussed, the first LNG proposals in BC were designed to import natural gas from Asia into the North American market (Natural Resources Canada, 2017). Imports and exports of LNG are directly linked to the domestic price of LNG relative to the price of LNG in other markets. In the early-mid 2000's, when the Province was planning to import LNG from Asia, the domestic price of LNG was at one point approximately 30% higher than the price in Asia, as seen in Figure 1. These prices were not sustained: prices in Asia increased, while prices in North America decreased (BP, 2016), thus removing the incentive to import LNG into North America.

The large price gap that was formed between the North American and Asian prices of LNG sparked the interest of foreign investors to develop an LNG industry in North America with the purpose of exporting to Asia. British Columbia was viewed by Asian investors as a good region to develop an LNG industry due to its substantial supply of natural gas (BC Ministry of Energy and Mines, 2011). In addition, BC is located on the Pacific coast allowing for direct tanker transport to Asia (BC Ministry of Energy and Mines, 2011). Interest among Asian investors resulted in the proposal of 20 LNG plants between 2010 and 2016 (National Energy Board, 2018).

The BC provincial government saw the development of an LNG industry as a way to generate provincial revenue through various economic policies and fiscal mechanisms and cited the establishment of a $100 billion Prosperity Fund with the goal of ensuring communities, First Nations, and all citizens of BC would benefit from LNG projects (Government of BC, Office of the Premier, 2013). The priorities of this fund were eliminating provincial debt, reducing taxes for the public, and sustaining the BC economy (Government of BC, Office of the Premier, 2013). In addition, the provincial government believed the LNG industry would create a significant number of jobs within the province; 75,000 person-years of employment based on their forecasts (Government of BC, Office of the Premier, 2013). The provincial government was very optimistic about this opportunity and promised the public a booming LNG industry consisting of two to three LNG projects up and running by 2020 (Government of BC, Office of the Premier, 2011).

The revenue-generating potential of LNG in BC was supported by provincial government-commissioned revenue projection reports completed by two major accounting firms: Grant Thornton (2013) and Ernst & Young (2013). Assuming production of 82 million tons of LNG per year (mta), Grant Thornton (2013) projected total government revenues of between $130 and $180 billion, and Ernst & Young (2013) projected $79 billion. At production of 120 mta of LNG, Grant Thornton (2013) projected between $160 billion and $270 billion of government revenue, and Ernst & Young (2013) projected $162 billion of government revenue. These projections by Grant Thornton (2013) and Ernst &

Young (2013) assumed a 20-year operating period beginning in 2018 and ending in 2037.

3.2. Proposed Projects

A total of 20 LNG plants were proposed in BC between 2010 and 2016, and as of August 2018 none have begun construction (Government of BC, n.d.; (National Energy Board, 2018). The proposed locations of these plants can be seen in Figure 2. Five of these proposed projects are located on the Southern Coast; in Squamish, Richmond, and on Vancouver Island. There are 14 proposed projects located on the Northern Coast near Prince Rupert and Kitimat. A total of 16 projects have received export licenses and 4 have received federal and provincial environmental assessment certificates (Government of BC, n.d.). A list of the proposed projects is provided in Table 1. Included within these project proposals are pipelines that connect the coastal LNG plants to the natural gas sources in Northeastern BC. The majority of BC's natural gas resources are located in Horn River Basin, Liard Basin, Montney Basin, and Cordova Embayment (Government of BC, n.d.). The location of these natural gas stocks can be seen in Figure 2.

According to the BC provincial government, natural gas will be transported to LNG plants via pipelines. Currently there are six proposed pipelines: three to Kitimat (Pacific Trail Pipeline, Pacific Northern Gas Transmission Pipeline Expansion, and Coastal GasLink Pipeline), two to Prince Rupert (Westcoast Connector Gas Transmission and Prince Rupert Gas Transmission), and one to

Squamish (Eagle Mountain – Woodfibre Gas Pipeline) (Government of BC, n.d.). So far, all proposed pipelines have received a BC Environmental Assessment Certificate except for the Pacific Northern Gas Transmission Pipeline Expansion and the Pacific Trail Pipeline. Once the natural gas is transported via pipeline and liquefied in the plants, the LNG will be shipped via tanker to Asia.

Figure 2. Map of proposed LNG projects in British Columbia. From “LNG in BC Map,” by Government of BC, 2018, https://www2.gov.bc.ca/assets/gov/farming-natural-resources-and-industry/natural-gas-oil/liquified-natural-gas/222_lng_in_bc_map.pdf. Copyright 2018 by Government of BC.

Table 1. Proposed LNG plants in BC

Project	Location	Status (approvals granted)
Aurora LNG Cancelled	Grassy Point, north of Prince Rupert	NEB Export Licence
Canada Stewart Energy Project	near Stewart, British Columbia	NEB Export Licence
Cedar LNG	Douglas Channel, Haisla project lands	NEB Export Licence
Discovery LNG	Campbell River	NEB Export Licence
Grassy Point LNG Cancelled	Grassy Point, north of Prince Rupert	NEB Export Licence
Kitimat LNG	Kitimat	NEB Export Licence, BC Environmental Assessment Certificate, and Canadian Environmental Assessment Certificate
Kitsault Energy Project	Kitimat	NEB Export Licence
LNG Canada	Kitimat	NEB Export Licence, BC Environmental Assessment Certificate, and Canadian Environmental Assessment Certificate
NewTimes Energy Ltd.	Prince Rupert	NEB Export Licence
Nisga'a LNG	Near Prince Rupert	None
Orca LNG	Prince Rupert	NEB Export Licence
Pacific NorthWest LNG Cancelled	Prince Rupert	NEB Export Licence, BC Environmental Assessment Certificate, and Canadian Environmental Assessment Certificate
Steelhead LNG: Malahat LNG Cancelled	Near Mill Bay, Vancouver Island	NEB Export Licence
Steelhead LNG: Sarita LNG	Sarita Bay, Vancouver Island	NEB Export Licence
Triton LNG	Undecided (either Kimitat Or Prince Rupert)	None
Watson Island LNG	Watson Island near Prince Rupert	None
WCC LNG Ltd.	Prince Rupert	NEB Export Licence
WesPac	Delta	NEB Export Licence
Woodfibre LNG	Squamish	NEB Export Licence, BC Environmental Assessment Certificate, and Canadian Environmental Assessment Certificate
Prince Rupert LNG Cancelled	Prince Rupert	None

Note. Information on LNG projects in BC from Government of BC (n.d.)

3.3. Current State of LNG Industry in BC

In recent years, the price for LNG imports in Asia has declined and the price differential that created the opportunity to export BC LNG has been significantly eroded. Between 2012 and 2016, the price of natural gas in Asia decreased from approximately $23/mcf to $9/mcf (2018 CAD) (BP, 2016). This price differential erosion has effectively undermined the original economic rationale for developing LNG in BC. The decrease in the LNG price gap has caused foreign investors to become hesitant in making further investments, which has become evident with the recent LNG plant cancellations (Corkhill, 2018). Changing market conditions for LNG has made it challenging for the Province to deliver on its promises to develop an LNG industry in BC. In response, the Province has made some changes to the LNG fiscal regime in hopes of making the industry more competitive and enticing companies to make further investments in the BC LNG industry (Government of BC, Office of the Premier, 2013).

As of June 2018, only one LNG project has made final investment decision to proceed: the Woodfibre project in Squamish (Government of BC, Office of the Premier, 2016). This announcement came in late 2016 soon after the announcement of a new BC Hydro “eDrive” rate subsidy for electricity supply for LNG projects (Government of BC, Office of the Premier, 2016). As of June 2018, construction of the plant has not yet begun.

Recently, five LNG plants have been cancelled: Shell’s Prince Rupert LNG, Petronas’ Pacific NorthWest LNG, Woodside Petroleum’s Grassy Point

LNG, Inpex and JGC Corp's Aurora LNG, and Steelhead LNG Corp and Malahat Nation's Steelhead LNG (Corkhill, 2018). Shell's cited reason for cancelling the Prince Rupert LNG project was to allow the company to focus efforts on the LNG Canada project in Kitimat (a joint venture with PetroChina Co. Ltd., Korea Gas Corp. and Mitsubishi Corp.) (Cryderman, 2017). Other LNG companies cited the currently unfavourable economic environment as the primary reason for cancelling their respective projects (Corkhill, 2018) Currently, no development has begun on LNG plants in BC, meaning that there is still time to critically analyze the potential revenue impacts associated with LNG development and inform potential changes.

3.4. BC Natural Gas Royalties

In accordance with the Petroleum and Natural Gas Act, natural gas producers in BC are required to pay royalties on gas sold (BC Ministry of Finance, 2014). Natural gas royalties in BC are ad valorem (BC Ministry of Finance, 2014), meaning the royalty rate is based on a percentage of the estimated value of the natural gas (IMF, 2012). Calculating the applicable royalty rate is a complicated process and depends on a number of factors. In short, the applicable royalty rate depends on whether the natural gas extraction project is on free-hold[1] or Crown

[1] ""Freehold land" is land where the Crown has granted ownership of underlying oil and natural gas to a person. Production of oil and natural gas from freehold lands does not require a lease under the *Petroleum and Natural Gas Act*" (BC Ministry of Finance, 2014, p. 35).

land[2]; the gas is considered conservation[3] or non-conservation gas[4]; whether the gas is Base 9[5], Base 12[6], or Base 15[7]; the reference price of the gas[8]; and the select price of the gas[9] (BC Ministry of Finance, 2014). Without any discounts being applied, the effective royalty rate for a natural gas producer can range from \$9 per thousand cubic meters (10^3m^3) to \$27 per 10^3m^3. There are, however, various discounts that can be applied to this rate such as the Natural Gas Deep Well Credit, Infrastructure Credits, Low Productivity Well Royalty Reduction,

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[2] ""Crown land" is land where the Crown has retained ownership of underlying oil and natural gas. Production of oil and natural gas from Crown lands requires a lease under the *Petroleum and Natural Gas Act*" (BC Ministry of Finance, 2014, p. 35).

[3] ""Conservation Gas" is gas produced from an oil well where the marketable gas is conserved, but does not include gas from an oil well granted concurrent production status under section 97 of the *Petroleum and Natural Gas Act*" (BC Ministry of Finance, 2014, p. 35).

[4] ""Non-conservation Gas" is gas other than Conservation Gas and is classified into Base 15, Base 12 and Base 9" (BC Ministry of Finance, 2014, p. 35).

[5] "Base 9**:** Non-conservation gas, other than revenue sharing gas, produced from well events

(a) for which the entire spacing area is

(i) in a lease that was disposed of under section 71 of the Act after May 1998, or

(ii) in a lease that was issued from a permit or license that was disposed of under section 71 of the Act after May 1998" (BC Ministry of Finance, 2014, p. 35).

[6] "Base 12**:** Non-conservation gas, other than revenue sharing gas, produced from well events that are not Non-Conservation Gas, Base 15 or Non-Conservation Gas, Base 9" (BC Ministry of Finance, 2014, p. 35)

[7] "Base 15 / Freehold**:** Non-conservation gas that is produced from well events in a well having a spud date before June 1, 1998, or is revenue sharing gas." (BC Ministry of Finance, 2014, p. 35)

[8] ""Reference Price" for a producer's gas is the greater of:

(i) the Producer Price for the producer's gas in the month, and

(ii) the Posted Minimum Price for the month in which it is available for disposition" (BC Ministry of Finance, 2014, p. 35)

[9] ""Select Price" is a price set by Order of the Administrator for each calendar year. It is a mechanism by which the Reference Price at which the minimum royalty rate takes effect can be adjusted for inflation. It is currently \$50 per 103m3 until further notice" (BC Ministry of Finance, 2014, p. 35)

Marginal Well Royalty Reduction, and the Ultramarginal Well Royalty Reduction[10] (BC Ministry of Finance, 2014).

3.5. LNG Economic Policies

3.5.1. Provincial Goals and Strategies

To take advantage of the price differential between North America and Asia, the Province stated that there would be up to three operational LNG projects by 2020 (Government of BC, 2011). As part of the plan to develop LNG in BC, the Province outlined goals and strategies in their 2012 and 2013 LNG strategy reports. The three primary goals presented in these reports were:

1. Keep BC competitive in the global LNG market;
2. Maintain BC's leadership on climate change and clean energy; and
3. Keep energy rates affordable for families, communities and industry.

   (BC Ministry of Energy and Mines, 2012; 2013).

Keep BC competitive in the global LNG market

From a marketing standpoint, part of developing a successful business or industry is ensuring your firm stays competitive with other firms. In 2012 and 2013, demand for LNG was growing substantially in China and Japan. BC faces direct competition to meet this demand from Australia, Qatar, the USA, Russia,

[10] Royalty credits and reductions are offered to encourage certain types of drilling projects and keep wells operating (BC Ministry of Finance, 2014).

and Algeria (Melikoglu, 2014; BC Ministry of Energy and Mines, 2012). The Province, however, recognizes many of its competitive advantages over these countries, including:

1. “Lower shipping costs, thanks to [its] proximity to Asia;
2. Secure, stable government;
3. Vast natural gas reserves;
4. High environmental standards;
5. Potential to access clean energy;
6. Positive relationships with First Nations peoples;
7. A well-established service sector; and
8. Strong, updated regulations.”

(BC Ministry of Energy and Mines, 2012, p. 8)

Additionally, the Province has outlined strategies for achieving its goal of keeping BC LNG competitive in the global marketplace, including:

1. Ensure an efficient regulatory system;
2. Launch marketing campaigns in Asia;
3. Streamline the federal and provincial assessment processes and reduce the amount of overlap in the two processes;
4. Explore collaborative approaches to LNG pipeline development;
5. Collaborate and build working partnerships with First Nations and stakeholders; and
6. Prepare the LNG workforce by increasing post-secondary training opportunities for British Columbians.

(BC Ministry of Energy and Mines, 2012; 2013).

Although the Province has made progress in its efforts to keep BC LNG competitive, its competitors, including Australia and Qatar, have already begun exporting LNG, whereas BC has not (BP, 2016).

Maintain BC’s leadership on climate change and clean energy

Natural gas is considered by many to be a transitional source of energy that is meant to temporarily replace energy sources with high levels of emissions, primarily coal and oil, in an attempt to meet global climate targets (Stephenson & Shaw, 2013). It is understood that developing BC's LNG industry will negatively impact the Province's ability to meet its emission targets as part of BC Climate Action Plan (BC Ministry of Energy and Mines, 2012; 2013). It is argued, however, that this is an acceptable trade-off for the global benefit (BC Ministry of Energy and Mines, 2012). The Province's strategies for achieving this goal are as follows:

1. Follow the Climate Action Plan;
2. Grow the domestic market for natural gas as transportation fuel;
3. Encourage the use of clean fuel for powering LNG plants; and
4. Work with industry, First Nations, and clean energy producers to develop sources of supply.

(BC Ministry of Energy and Mines, 2012; 2013).

Keep energy rates affordable

The Province's third goal, to keep energy rates affordable, applies to both industrial and residential consumers. There are three primary strategies that the Province has outlined to achieve affordable energy rates, including:

1. Assess future energy needs of industry and the rest of province. This includes BC Hydro's Integrated Resource Plan which outlines growth of electricity demands over next 20 years;
2. Implement self-sufficient energy policy to allow for flexibility in reducing increases to energy rates; and
3. Provide industry with opportunities to use cost competitive clean energy to power LNG plants.

(BC Ministry of Energy and Mines, 2012; 2013).

3.5.2. LNG Income Tax

Concurrent with the recent decline in the LNG price differential, the provincial government made some key changes to the fiscal regimes that apply to natural gas and LNG. One of these key changes was the addition of the LNGIT, which will be described in detail below. The LNGIT was developed to capture a portion of the rents generated by the sale of LNG (Lee, 2014). The LNGIT was proposed in 2013 with the goal of ensuring British Columbia would collect a fair share of the rents generated from selling LNG to international markets, over and above the rents generated from natural gas (BC Ministry of Finance, 2014). When the LNGIT was first proposed, the applicable rates were 1.5% of an LNG plant's net profits until capital costs were recovered and total profits exceeded total capital costs of the plant, after which a rate of 7% would apply. When the tax was eventually put into legislation in 2014, the rates changed. The 1.5% rate still applied to the net operating profits of an LNG plant before capital costs were recovered. Once capital costs were recovered, the applicable rate would be 3.5% of the LNG plant's net profits, which then would increase to 5% in the year 2037 (Government of BC, 2014).

Net operating income and net income for LNG plants are defined under the *Liquefied Natural Gas Income Tax Act* (SBC 2014, c 34). An LNG plant's operating income is the loss or profit as a result of operating activities (SBC 2014, c 34). The net income of an LNG plant is derived by taking the net operating income from a taxation year and making any relevant deductions. The formula for net income is as follows: Net income = net operating income from taxation year + recaptured capital investment account balance – net operating loss account deduction – capital investment account deduction (SBC 2014, c 34). Deductions can be applied to bring the net income to zero, but net income cannot be reduced to a negative balance (SBC 2014, c 34).

There are four deductions that can be applied to the LNGIT. The Net Operating Loss Account is an accumulation of operating expenditures that results from the LNG plant's revenues being lower than the operating costs (SBC 2014, c 34). This account is then deducted from future years in which net operating incomes are positive (SBC 2014, c 34). The Capital Investment Account is an accumulation of capital expenditures that is deducted from the LNG plant's net income (SBC 2014, c 34). Investment Allowance is a budget that can be spent on tangible capital and deducted from net income (SBC 2014, c 34) based on the following formula: 3% x 0.75 x the current average balance of your adjusted CIA (SBC 2014, c 34). The Closure Tax Credit is a deduction offered in the final year of an LNG facility before it ceases operations (SBC 2014, c 34). This credit amount is the lesser of 5% of the plant's eligible expenditures for the LNG facility, or the amount of tax paid on net income over the life of the LNG plant (SBC 2014, c 34).

The LNGIT only applies to liquefaction activities at an LNG plant in British Columbia. An LNG plant comes into existence when construction begins on land that LNG plant is intended to operate (SBC 2014, c 34). An LNG plant is defined in the *Liquefied Natural Gas Income Tax Act* (SBC 2014, c 34) as tangible personal property and improvements used or intended to be used for any of the following:

- Liquefying natural gas;
- Receiving or measuring natural gas delivered to the series of systems;
- Removing natural gas liquids from natural gas and separating those liquids;
- Storing natural gas liquids (such as propane, butane, and ethane);
- Storing LNG;
- Measuring of LNG that are to be loaded for shipment or regasification;
- Loading LNG for shipment;
- Supporting the loading of LNG;
- Transmitting LNG for regasification;
- Electrical power generation to power LNG plant;
- Compliance with health, safety, and environmental standards required by law;
- Acid removal;
- Dehydration;
- Mercury removal; and
- Refrigeration

Some related infrastructure that is not considered part of the LNG plant, and therefore not covered under the *Liquefied Natural Gas Income Tax Act* (SBC 2014, c 34), include:

- Feedstock pipelines;
- Vehicles or vessels used to transport LNG or natural gas liquids; and
- Pipelines used to transport LNG, natural gas liquids, or natural gas

On March 22, 2018, the new BC provincial government announced a new framework for LNG development in British Columbia (Government of BC, Office of the Premier, 2018). The major part of this new framework was the elimination of the LNGIT (Government of BC, Office of the Premier, 2018). The other key components of the new framework are relief from provincial sales tax, new greenhouse gas (GHG) emission standards, and the continuation of the eDrive subsidy, which will be described below. The stated objectives of the provincial government's new LNG framework are to:

- "Guarantee a fair return for BC's natural resources;
- Guarantee jobs and training opportunities for British Columbians;
- Respect and make partners of First Nations; and
- Protect BC's air, land and water, including living up to the Province's climate commitments" (Government of BC, Office of the Premier, 2018, p. 1)

This new fiscal regime was developed as a result of discussions with LNG Canada, which the provincial government hopes will make a positive final investment decision by the end of 2018 (Government of BC, Office of the Premier, 2018).

3.5.3. Natural Gas Tax Credit

The natural gas tax credit serves to reduce the amount of provincial CIT owed by a company that carries out liquefaction activities (McCarthy Tetrault, 2016). The credit is applied to the cost of natural gas purchased for these liquefaction activities. Beginning January 1, 2017, the tax credit rate changed from 0.5% of the LNG corporation's eligible cost of natural gas to a maximum of 3% (McCarthy Tetrault, 2016). When the credit is applied to the BC Provincial CIT, this results in a rate decrease from 11% to 8% (McCarthy Tetrault, 2016). Unused credits can be pooled and used in subsequent taxation years (McCarthy Tetrault, 2016). When coupled with the 3.5% LNGIT, the implementation of the natural gas tax credit raises the question of what the net provincial revenue impact will be as a result of the two policies.

3.5.4. Long-term Royalty Agreement

In 2015, the Government of BC introduced section 78.1 “Royalty agreements” as part of the Miscellaneous Statutes Amendment Act (Government of BC, Office of the Premier, 2015). This piece of legislation allows the Minister of Natural Gas and Development to enter into LTRAs with LNG corporations with durations exceeding 20 years (Government of BC, Office of the Premier, 2015). These LTRAs outline binding commitments made by both sides: natural gas operators and the provincial government (Grieve & Turner, 2015). According to the Grieve & Turner (2015), LTRAs provide benefits to the operators and the Province. To the benefit of the operators, LTRAs are meant to provide increased certainty in a volatile global natural gas market for a significant period of time (Grieve & Turner, 2015). Royalties for most natural gas production in BC is based on an ad valorem rate that varies with the price of natural gas. The LTRA royalties, however, are based on relatively pre-determined ad valorem rates that vary minimally with changes in natural gas prices, thus providing greater certainty to producers on the rate that they will pay (Grieve & Turner, 2015). Additionally, LTRAs appear to offer a much simpler method for calculating payable royalties than the general oil and gas royalty regime because they exclude many of the various rate changes and deductions that apply to non-LTRA gas (Grieve & Turner, 2015).

According to the Province, LTRAs also provide potentially significant benefits for the provincial government (Grieve & Turner, 2015). One benefit is that by signing an LTRA, the natural gas operator commits to producing a steady production of natural gas (Grieve & Turner, 2015). The LTRA sets out minimum volumes that must be produced each year that range between 159.46 billion cubic feet (bcf) and 380.66 bcf (BC Ministry of Natural Gas Development, 2015). If the producer does not meet these minimum production volumes, then an alternative royalty formula is used (BC Ministry of Natural Gas Development, 2015). A second benefit is that the LTRA outlines investment commitments for producers. Natural gas producers must make long-term infrastructure investments of $3 billion within the first 5 years of signing the LTRA (Grieve & Turner, 2015). Additionally, producers must make ongoing investments of $1 billion per year (3-year average) that continue until production reaches 1.85 bcf/day (Grieve & Turner, 2015). The production and investment commitments are designed to incentivize incremental natural gas production for the LNG sector that may not otherwise be produced.

The general natural gas royalty rate for gas sold to traditional markets, domestically and to the United States, ranges from 9% to 27% depending on a series of conditions as described previously (BC Ministry of Finance, 2014). With the LTRA, the royalty rates for natural gas are primarily predetermined. The royalty rates start at 6.06% in 2016 and rise each year to a maximum rate of 13.36% in 2038 (Government of BC, 2015c). These rates change slightly with fluctuating natural gas market prices due to a reverse pricing mechanism. If the AECO natural gas price falls below $2.50 per gigajoule, the royalty rate can be multiplied by a factor of up to 1.8 (Government of BC, 2015c). If the AECO natural gas price increases above $6 per gigajoule, the royalty rate can be multiplied by a factor between 1 and 0.6 (Government of BC, 2015c).

3.5.5. Accelerated Capital Cost Allowance for LNG

The Accelerated Capital Cost Allowance (CCA) for LNG is a federal tax incentive program that was announced in 2015. This regulation made two changes to LNG-related asset deprecation policy (Department of Finance Canada, 2015; McCarthy Tetrault, 2016). First, the CCA depreciation rate for Class 47 liquefaction-related assets, including equipment and structures, changed from 8% to 30% (Department of Finance Canada, 2015; McCarthy Tetrault, 2016). Second, the CCA rate for non-residential LNG buildings changed from 6% to 10% (Department of Finance Canada, 2015; McCarthy Tetrault, 2016). These changes increase the depreciation expenses that can be recorded by LNG plants each year, which increases income tax deductions (McCarthy Tetrault, 2016). The result of the accelerated CCA regulation is that LNG companies can recover capital costs more quickly (McCarthy Tetrault, 2016).

3.5.6. BC Hydro's eDrive Electricity Rate

BC Hydro's eDrive electricity rate is a special subsidized rate applicable to LNG plants that was introduced in 2016. LNG companies that decide to power their plants with BC Hydro receive electricity rates of approximately $53.60 per kilowatt hour (Nikiforuk, 2016; Shaffer, 2016). This subsidized rate is roughly 40% below the cost of hydroelectricity production in BC (Shaffer, 2016). An LNG plant that takes advantage of the eDrive rate would produce fewer GHG emissions compared to a plant powered by natural gas, as well as potentially reduce capital costs by replacing internally generated power capacity with lower cost hydro. Soon after the eDrive rate was announced, the proposed Woodfibre project announced its positive final decision to proceed and develop the LNG plant, taking advantage of the eDrive rate (BC Hydro, 2016). It is estimated that the eDrive rate will result in cost savings for the Woodfibre LNG plant of $34 million per year, adding up to $860 million over lifetime of project (Nikiforuk, 2016; Shaffer, 2016). It is expected, however, that these savings for LNG companies will be counterbalanced with higher rates for public BC Hydro customers (Shaffer, 2016).

3.5.7. GHG Policy

BC has legislated GHG targets in the Greenhouse Gas Reduction Targets Act (SBC 2007), requiring a reduction in GHG emissions of 33% below 2007 levels by 2020 and a reduction of 80% below the 2007 levels by 2050. Several sources have voiced concerns regarding the impact of GHG emissions from LNG development (Globe Advisors, 2014; Lee, 2012; Pembina Institute, 2013). The Province appears to have responded to these concerns by stating that LNG can reduce world GHG emissions by replacing more GHG intensive fossil fuels used globally, such as coal (Government of BC, n.d.). In 2014, the provincial government also introduced the emissions benchmark of 0.16 CO_2 tonnes per tonne of LNG produced by BC's LNG sector (McCarthy Tetrault, 2016). These regulations only pertain to the LNG plant and not to upstream activities. LNG plant owners can meet the 0.16 CO_2 benchmark in a variety of ways. One option is to increase the energy efficiency of the plant or increase the use of clean energy such as hydro (McCarthy Tetrault, 2016). A second option is to purchase emission offsets from emission reduction projects (McCarthy Tetrault, 2016). A third option is to contribute to a technology fund at a rate of $25 per tonne of CO_2 (McCarthy Tetrault, 2016).

3.6. Estimating LNG Benefits in BC

Current research has taken a quantitative approach to determine the economic benefits that British Columbians can expect from the LNG industry. Most notably, three studies have estimated the revenues that the provincial government can expect: Grant Thornton (2013), Ernst & Young (2013), and Lee (2014). The summarized results of these studies are shown in Table 2. The Grant Thornton (2013) and Ernst & Young (2013) studies share common limitations. One limitation is that the studies are based on "generic" LNG plants instead of specific proposed LNG plants. Since the financial models were not based on actual proposed LNG project parameters, the capital and operating costs used in the modeling may not be accurate estimates of project economics. A second limitation is that the studies relied on LNG price forecasts supplied by the US Energy Information Administration and did not conduct a sensitivity analysis accounting for potential changes in future LNG prices (Ernst & Young, 2013; Grant Thornton, 2013). A third limitation is that the sources of estimated revenues include personal income taxes from employment as a result of the development of an LNG industry in BC. One problem with this is that the studies ignored the incremental costs to government for providing healthcare, housing, and other services to the workers being employed in the LNG industry that must be deducted from total revenue to estimate the net revenue gain (Shaffer, 2010). A second problem is that the revenue estimates were produced by the BC Input-Output Model (Ernst & Young, 2013; Grant Thornton, 2013). The BC Input-Output Model measures direct, indirect, and induced effects in the BC economy resulting from various projects and policies (Hallin, 2010). Input-output models are known to "have severe limitations, exaggerate benefits and ignore economic costs" (Allan, 2012, p. 4). The use of the BC Input-Output model to estimate revenue generated by the LNG industry likely resulted in overestimations. A fourth limitation of the studies is that they did not show the distribution of revenues between the private company and the provincial government. Not having this comparison in economic benefits inhibits the ability of decision makers to determine whether the distribution is acceptable. Additionally, these studies did not include any comparisons with other countries developing LNG industries, such as Australia. A fifth limitation is that the studies did not present the government revenue in present value dollars, which resulted in overestimations in revenues. This is based on the concept of time valuation, and the idea that one dollar in the present is worth more than one dollar in the future. A sixth limitation of these studies is that upstream natural gas royalty revenues were included as sources of government revenue using the regular natural gas royalty regime, which is based on the questionable assumption that natural gas supplied to the LNG facility is all incremental production that would not be produced in the absence of building LNG facilities. Some proportion of this natural gas is likely to be produced regardless of LNG development, and the royalty payments therefore should not be completely attributed to LNG. A seventh limitation of these studies is that they used the previously proposed 7% LNGIT rate instead of the 3.5% rate that was enacted, as the studies were completed before the LNGIT was put into legislation.

Table 2. Estimated total revenues for provincial government over 20-year period

	Government revenue at a production of 82 million tons per year (mta) (2012 billion $)	Government revenue at a production of 120 mta (2012 billion $)
Grant Thornton	130-180	160-270
Ernst & Young	79	162

Note. Data for Estimated total revenues for provincial government over 20-year period from Grant Thornton (2013) and Ernst & Young (2013).

Table 3. Estimated total revenues for provincial government over 30-year period

	Government revenue at a production of 17.7 mta (2014 billion $)	Government revenue at a production of 43.3 mta (2014 billion $)
Lee	20	48

Note. Data for Estimated total revenues for provincial government over 30-year period from Lee (2014).

The Lee (2014) study also estimated provincial revenues stemming from the development of an LNG industry in BC (

Table 3). Lee's estimates of government revenue are significantly lower than the Grant Thornton and Ernst & Young estimates because Lee corrects for some of the questionable assumptions used in these other studies. For example, while Grant Thornton and Ernst & Young include income and sales tax revenues in their revenue estimates, Lee omits these two tax revenue sources on the grounds that the revenue is not necessarily incremental. Another strength of Lee's study compared to Grant Thornton's and Ernst & Young's is that it included a sensitivity analysis that accounted for various potential future prices, production, and capital cost overruns. One limitation of Lee's (2014) study is that, like the Ernst & Young and Grant Thornton studies, it is assumed that the upstream natural gas used to supply the LNG plants is incremental and would not be produced without LNG development. A second limitation of Lee's (2014) analysis is that it does not include property taxes as an incremental source of revenue. A third limitation of Lee's (2014) analysis is that the BC Hydro eDrive, natural gas tax credit, and LTRA subsidies are excluded from the analysis. A fourth limitation is that Lee's study does not show the distribution of revenues, private versus public, resulting from the development of the LNG industry in BC. Comparing the revenue earned by the resource owner to the revenue retained by the resource producer provides support in determining whether the resource owner is collecting a fair return on the resource. A fifth limitation is that Lee used the previously proposed 7% LNGIT rate instead of the 3.5% rate that was put into legislation, as the analysis was completed before the LNGIT was put into legislation.

Chapter 4. Methods

4.1. Literature Review

I conducted a literature review, reviewing academic articles, grey literature, and provincial government reports and press releases. First, I reviewed academic sources to obtain general and contextual information on Canadian resource policy, global LNG development, and natural resource fiscal mechanism development best practices. Second, I reviewed relevant grey literature on studies that quantified the economic impacts of BC's LNG fiscal regime. This included reports completed by Grant Thornton (2013), Ernst & Young (2013), and Lee (2014). Third, I reviewed provincial government reports and press releases that contained the goals and objectives associated with LNG development in BC.

4.2. Document Analysis

I conducted document analyses to understand the mechanics of BC's LNG fiscal policies and the applicable royalty and tax rates. Document analysis is a qualitative research method of evaluating document text to "elicit meaning" and pull out key information on a specific topic (Bowen, 2009, p. 27). Additionally, I conducted analyses to gather the relevant inputs necessary for the quantitative analysis. This information was obtained from provincial government and non-governmental organization sources.

4.3. Key Informant Interviews

I conducted semi-structured key informant interviews to answer the qualitative research questions for this study. Key informants were recruited for the study using email. A total of six key informants were interviewed between August 2017 and January 2018. These interviews followed best practices as set out by Creswell (2013) including respecting the study site and participants, making sure the participants receive benefits from participating in the study, avoiding deceiving the participants, respecting power imbalances, avoiding the collection harmful information, and respecting the privacy of participants. The key informants represented the perspectives of industry, the BC provincial government, First Nations, and third-party natural resource management experts. I sought out interview participants based on their direct knowledge of the BC's proposed LNG projects and the associated economic policies. Interviews lasted 30-60 minutes and covered several topic areas including the process, analysis, rationale, and evaluation of the LNGIT, the natural gas tax credit, and the LTRA. For the rationale and evaluation topic areas, I asked the participants to give their opinion of the LNG economic policies and fiscal regime from natural resource management and public policy perspectives. The complete interview guide can be found in the appendix. Interviews were recorded with an audio recorder, transcribed, then coded using theoretical thematic content analysis (Braun & Clarke, 2006). I identified key themes from the interviews using a semantic and inductive approach, which involved eliciting key themes directly from the answers provided in the interviews (Fereday & Muir-Cochrane, 2006).

Participating in the interviews required the key informants to have direct knowledge of the overall economics associated with LNG in BC as well as the economic policies related to LNG development. Numerous potential recruits that were asked to participate in the study felt they did not have enough knowledge of the specific policies, and as a result declined to participate. Additionally, many potential recruits that were perceived to have the knowledge required to answer the interview questions declined to participate. The total number of key informants that participated in the study was quite low. It is believed that this is mainly due to the specificity and the potentially contentious nature of the questions being asked.

4.4. Quantitative Analysis

4.4.1. Evaluating the economic feasibility of an LNG project in British Columbia under the new LNG royalty regimes

As of August 2018, only one of the 20 proposed LNG projects in BC has received a positive final investment decision from the proponent: Woodfibre LNG. Consequently, Woodfibre is used to estimate revenue impacts because it is the most advanced project in BC and the financial information for this proposed LNG plant is publicly available. Woodfibre LNG is one of the smallest LNG plants proposed in BC and is projected to produce approximately 2.1 million tonnes of LNG per year (Woodfibre LNG, n.d.). According to the proponent, the Woodfibre LNG plant is projected to generate an estimated $91 million (converted to 2018 CAD) of revenue per year for all three levels of government, adding up to a total revenue of roughly $2.3 billion over 25 years of operation (Woodfibre LNG, n.d.). Construction on Woodfibre LNG, however, has not yet been substantially started.

The purpose of the quantitative analysis is to calculate the net impact of the new fiscal regime on government revenues from an LNG plant. This is achieved by separating the analysis into two primary components and utilizing two connected models. The first component consists of estimating the pretax earnings that would be generated by the Woodfibre LNG plant. This part of the analysis is conducted using an LNG-specific discounted cash flow model that will be discussed in detail below. The second component of the quantitative analysis estimates the incremental government revenues from the Woodfibre LNG plant and then compares this to the revenues generated by the natural gas sector by using a second discounted cash flow model, which will be discussed in detail in the following section.

After conducting a literature review on project feasibility models, I decided to conduct the first component of the analysis, estimating the pretax earnings of the Woodfibre LNG plant, using the Open Upstream Gas and LNG Model created by the Columbia Center on Sustainable Investment (CCSI). This is a static fiscal discounted cash flow model that was developed to evaluate the economics of LNG projects and increase public understanding of revenue flows from LNG projects (CCSI, 2016b). The model is also useful for demonstrating the trade-offs between various fiscal tolls and taxes. The Open Upstream Gas and LNG Model calculates the profitability of an LNG project based on a series of assumptions that are inputted by the user (CCSI, 2016b). The main inputs include the price of the natural gas supplied to the plant, the LNG sale price, the project start date, the lifetime of the project, the capital and operating costs of the project, the discount rate, and the fees and tolls that are collected by the government. The model categorizes these assumptions into the three main components of an LNG project: the upstream supply, the transmission pipeline, and the LNG plant (CCSI, 2016b). The main outputs of the model required for my analysis are the annual pretax earnings generated over the lifetime of the LNG plant and the NPV of the plant.

A concerning characteristic of the LNG industry is the uncertainty associated with future prices and production (Melikoglu, 2014). The Open Upstream Gas and LNG Model accounts for this uncertainty by performing a sensitivity analysis, which it displays as graphs in the output section of the model. The sensitivity analysis demonstrates how changes in the model assumptions would affect the profitability of the project. Changes in the natural gas supply price, the end product LNG sales price, LNG production volume, capital expenditures of the LNG plant, toll fees, and delay of project start date are all included within the sensitivity analysis (CCSI, 2016a). A major benefit of the incorporation of a sensitivity analysis in the model is that it allows for governments to determine a fiscal royalty regime's tolerance to changes in the LNG market (CCSI, 2016a).

The Open Upstream Gas and LNG Model has some major strengths that make it an appropriate model for addressing my research questions. One strength is that it is a publicly available and recently created resource. As a strong advocate for financial model transparency, CCSI (2016b) has offered the model free of charge online in hopes that it will serve as a learning tool for potential investors, governments, and the public. A second strength is that this is the first fiscal LNG model that includes the whole LNG value chain: upstream extraction, pipeline transmission, and the LNG plant (CCSI, 2016b). The most likely reason CCSI did this is that the value chain is interdependent: changes in tax policy on one component of the industry will impact the other components of the industry. For example, as the model shows, an increase in the LNG tax can reduce the input price of natural gas, which in turn can reduce natural gas royalty payments. Grant Thornton (2013), Ernst & Young (2013), and Lee (2014) only focused their analyses on the LNG plant portion of the chain and did not capture these types of interdependencies. The third strength is the flexibility of the model in accommodating different commercial structures. Each portion of the LNG value change can be owned by a different investor, which makes this model highly applicable to BC where natural gas suppliers are relatively separate from LNG pipeline and plant owners (Lee, 2014). A fourth strength is that the model is designed to perform a sensitivity analysis. This allows for users to determine the impact of alternative royalty regimes, prices, production, costs, and volumes on project economics and distribution of project revenues. A fifth strength; which is demonstrated by De Silva, Simons & Stevens (2016), Weijermars (2013), and Cook et al. (2013); is that the discounted cash flow model provides the outputs necessary for determining the economic feasibility of a project: government take, return on investment, gross revenue, NPV, and internal rate of return (IRR). The studies performed by Grant Thornton (2013), Ernst & Young (2013), and Lee (2014) only focused on the gross revenue of the LNG projects, which does not fully assess the economic feasibility of the project and potential rents accruing to the Province.

4.4.1. Estimating incremental government revenues

The next step in the analysis is to calculate the incremental government revenues resulting from the LNG industry. This part of the analysis follows the multiple account benefit-cost analysis methodology developed by Shaffer (2010). Multiple account benefit-cost analysis is a well-recognized tool used to inform decision makers on the advantages and disadvantages of alternative projects from the perspective of society as a whole (Campbell & Brown, 2005; Shaffer, 2010). The taxpayer, or government, account in the multiple account analysis measures the net benefit or cost that accrues to the government as a result of the project (Shaffer, 2010). Measuring this account consists of estimating the incremental benefits or revenues accruing to government as a result of the project, less the incremental government expenditures (Shaffer, 2010). These are incremental revenues that would not otherwise accrue to government if the industry was not developed.

Estimating incremental revenues and expenditures for a major LNG project is challenging. Most fiscal impact studies of LNG in BC, for example, have estimated total revenues accruing to government without deducting incremental costs (Ernst & Young, 2013; Grant Thornton, 2013). Therefore, the estimates do not measure the net benefit to government. I estimate the net revenue using Shaffer's (2010) recommended multiple-account benefit cost analysis methodology. The analysis assumes that most tax revenue generated by a project is needed to cover indirect project costs such as health and education for employees (Shaffer, 2010). Therefore, much of the revenue is offset by costs, resulting in no change in net revenue (Shaffer, 2010). Following Shaffer's (2010) methodology, the sources of incremental government revenue from LNG that are not assumed to be offset by incremental government expenditures are the LNGIT, provincial CIT, property tax, and natural gas royalties under the LTRA. A cost that will be deducted from government revenue is the BC Hydro eDrive subsidy that applies to LNG plants powered by hydroelectricity. As previously described, the eDrive rate is a subsidized industrial rate that is approximately 40% below the cost of production in BC (Nikiforuk, 2016; Shaffer, 2016). Woodfibre has announced that it will take advantage of the eDrive rate to power the LNG plant (Government of BC, Office of the Premier, 2016).

The analysis consists of a comparison between two main scenarios. The first scenario is one in which the Woodfibre project is developed to supply Asian markets and generates incremental government revenue following the formula in Figure 3. There are two variants of scenario 1: 1a and 1b. The formula for scenario 1a is shown in Figure 3, where A is LNGIT revenue, B is provincial CIT, C is property tax revenue, D is upstream natural gas royalty revenue under the LTRA, and E is the value of the BC Hydro eDrive subsidy. Scenario 1b differs from 1a in that it does not include the LNGIT. Recently, the new BC Provincial

Government eliminated the LNGIT (Government of BC, Office of the Premier, 2018). These formulas are compared to the formulas used by Ernst & Young (2013), Grant Thornton (2013), and Lee (2014) in Figure 3.

In Scenario 2 it is assumed that the Woodfibre LNG plant is not built, and therefore the provincial government does not collect LNGIT, provincial CIT, or property tax from Woodfibre LNG. Additionally, the BC Hydro eDrive rate does not apply in Scenario 2 and it is assumed that hydroelectricity is sold at the standard rate to its traditional market. In Scenario 2 it is assumed that BC natural gas is shipped to traditional markets, including other provinces and the USA, rather than Asian markets. This means that the LTRA does not apply, and royalties are applied to the natural gas operators under the regular natural gas royalty regime.

Like Scenario 1, Scenario 2 is split into two Scenarios: 2a and 2b. In Scenario 2a it is assumed that natural gas production will remain constant, and there would be no incremental natural gas produced if LNG was developed. This assumption is based on the fact that the BC natural gas market is integrated into the North American market and the Woodfibre LNG plant is too small to impact netback prices for BC natural gas producers. If netback prices to producers do not change, the quantity of natural gas production will be the same with and without Woodfibre LNG. In Scenario 2b it is assumed that less natural gas is being produced in BC as a result of LNG not being developed (equal to 50% of the supply to Woodfibre plant). In other words, it is assumed in Scenario 2b that natural gas production would be higher with Woodfibre LNG than without it because Woodfibre would increase the demand for BC natural gas. This is described below in more detail. The equations for Scenarios 2a and 2b are shown in Figure 3, where D' is natural gas royalty revenue under the current natural gas royalty regime. To compare these scenarios, the values calculated in Scenarios 2a and 2b are subtracted from the values calculated in Scenarios 1a and 1b (Figure 3).

Other analyses:

Ernst & Young (2013)
and Grant Thornton (2013): $A + B + D' + F + G$

Lee (2014): $A + B + D'$

This analysis:

Scenario 1a: $A + B + C + D - E$

Scenario 1b: $B + C + D - E$

Scenario 2a: D'

Scenario 2b: $D' \times 0.5$

The difference in the revenues generated by:

Scenarios 1a and 2a: $(A + B + C + D - E) - D'$

Scenarios 1a and 2b: $(A + B + C + D - E) - (D' \times 0.5)$

Scenarios 1b and 2a: $(B + C + D - E) - D'$

Scenarios 1b and 2b: $(B + C + D - E) - (D' \times 0.5)$

Where:

$A\ is\ the\ LNGIT\ revenue$

$B\ is\ the\ CIT\ revenue$

$C\ is\ the\ property\ tax\ revenue$

$D\ is\ upstream\ natural\ gas\ royalty\ revenue\ under\ the\ LTRA$

$E\ is\ the\ BC\ Hydro\ eDrive\ subsidy$

$D'\ is\ the\ regular\ natural\ gas\ royalty\ regime\ revenue$

$F\ is\ personal\ income\ taxes\ revenue\ (for\ direct, indirect, and\ induced\ employment)$

$G\ is\ provincial\ sales\ tax\ (PST)\ revenue$

Figure 3. Scenario formulas.

The incremental government revenues resulting from BC's LNG industry are calculated using a discounted cash flow model developed using Microsoft Excel that is based on part of the Open Upstream Gas and LNG Model created by the CCSI. The incremental revenues are calculated by applying the relevant tax and royalty rates to the pretax earnings generated by the LNG plant, which are the primary outputs of the Open Upstream Gas and LNG Model. Incremental government expenditures associated with the project that are unique to the project are deducted from these incremental revenue sources. All other costs are assumed to be covered by the other taxes paid by the LNG plant that were not used to estimate incremental revenue. All figures in the model are in constant 2018 Canadian dollars.

Assumptions/Inputs:

Scenarios 1a and 1b

Since I will just be focusing on a single LNG plant, it is assumed that the operation of this plant is not substantial enough to require a significant increase in upstream natural gas production or prices. As shown in Table 4, the upstream transfer price for the LNG plant is $4.00/thousand cubic feet (mcf), based on McDaniel & Associates Consultants Ltd (2017) and Macquarie Research (2012). For my analysis, production levels are static for the estimated 25-year lifetime of the LNG plant, beginning in 2020 (Woodfibre LNG, 2015). Additionally, it is assumed that the supply of LNG from this plant will not be enough to affect downstream supply or prices. The current price of natural gas, as of May 2018, in Japan is approximately $11.50 CAD/mcf, which is referred to as the low export price in the analysis and can be seen in Table 4 (The World Bank, 2018). The high export price of $16.50/mcf is the average price of natural gas in Japan over the last 10 years, and the $13.50/mcf reference price is the 10-year average excluding the anomaly years of abnormally high natural gas prices (Table 4) (BP, 2016). The capital costs for Woodfibre are expected to range between $1.4 billion and $1.8 billion (2014 CAD) (Woodfibre LNG, n.d.). The reference value for capital costs in this analysis is $1.68 billion (2018 CAD). An additional capital cost required for development of the LNG plant is an impact benefit agreement (IBA) signed between Woodfibre LNG and the Squamish Nation. Although the

Squamish nation has signed an IBA with Woodfibre LNG, the value of the agreement was not made public at the time my research was completed and therefore the IBA used in this analysis assumes a lump sum payment of $25 million plus an annual payment of approximately 1% of annual net revenue of Woodfibre LNG (Table 6). According to Woodfibre LNG (2015), the operating costs for a plant this size are expected to be approximately $568 million per year. The pipeline tariff will be approximately $1.35/mcf and the shipping costs will be approximately $1.66/mcf (Murillo, 2014). The discount rate used for this analysis is 6%, which is a typical social discount rate for this type of project in Canada (Shaffer, 2010). Sensitivity analyses will be performed on the market price, the upstream transfer price, and the capital costs of the plant.

Table 4. Open Upstream Gas and LNG Model Assumptions and Inputs

Plant production	2.1 million tonnes/ year
Upstream transfer price	$2.92/thousand cubic feet(mcf) in 2020 +2%/year
Sales price (export)	$11.50/mcf (Low) $13.50/mcf (Reference) $16.50/mcf (High) (2018 CAD)
Plant lifetime	25 years
Start date	2018 (construction) 2020 (production)
Capital costs	$1.68 billion (2018 CAD)
Impact benefit agreement (Woodfibre)	$25 million + 1% of annual net revenue
Operating costs	$568 million/year (2018 CAD)

Gas pipeline tariff	$1.35/mcf (2018 CAD)
Shipping cost	$1.66/mcf (2018 CAD)
Discount rate	6%

Note. Data for LNG model assumptions and inputs from CERI (2014), McDaniel & Associates Consultants Ltd (2017), Woodfibre LNG (2015), and Woodfibre LNG (n.d.).

The incremental government revenue in this analysis comes from the provincial CIT, LNGIT, property taxes, and the upstream royalties under the LTRA. The LNGIT is omitted from government revenue in Scenario 1b. The BC CIT rate is regularly 11% but is decreased to 8% as a result of the natural gas tax credit (Table 5) (McCarthy Tetrault, 2016). For the LNGIT, a 1.5% rate applies to the net operating profits of a LNG plant until capital costs are recovered. Once capital costs are recovered, the applicable rate is 3.5% of the LNG plant’s net profit, which increases to 5% in the year 2037 (Government of BC, 2014). Woodfibre LNG will owe approximately $2 million in annual property taxes during the construction phase and $3 million once the plant is operational (Woodfibre LNG, 2015). Upstream natural gas royalty rates under the LTRA range between 6% and 13% (BC Ministry of Natural Gas Development, 2015).

Table 5. Incremental Government Revenue Assumptions and Inputs

Fiscal mechanism	Rate/impact
Provincial CIT	8% (after 3% Natural gas tax credit deduction)
LNGIT	1.5%, 3.5%, and 5%
Property taxes of plant	$2 million during construction $3 million per year during operation

Upstream royalties under the LTRA	6%-13%

Note. Data for incremental government revenue from BC Ministry of Natural Gas Development (2015), Government of BC (2014), McCarthy Tetrault (2016), and Woodfibre LNG (2015).

As shown in Table 5, the incremental government costs associated with developing Woodfibre LNG are a reduction in natural gas royalty rates from approximately 14% to between 6% and 13%. (Government of BC, 2015; McCarthy Tetrault, 2016; BC Ministry of Finance, 2014).

Table 6. Incremental government costs

Tax	Rate on revenue
BC Hydro eDrive subsidy	$34 million/year
Impact benefit agreement (BC Provincial Government)	$25 million (lump sum)

Note. Data for incremental government costs from Nikiforuk (2016) and Shaffer (2016).

Scenarios 2a and 2b

In Scenarios 2a and 2b, LNG is not developed and natural gas is sold to traditional markets. As seen in Table 7, the amount of natural gas sold in Scenario 2a to traditional markets is the same amount that would be sold to the LNG plant. The input price for the natural gas is $3.77/mcf, which is the average price of natural gas in BC over the past 10 years (BC Ministry of Finance, 2018) The input royalty rate under the regular royalty regime is 12.7%, which is the average royalty rate for BC gas in the past 10 years (BC Ministry of Finance, 2018). In Scenario 2b the amount of natural gas sold to traditional markets is 50% lower than the amount sold to the LNG plant based on the assumption that less natural gas is produced in BC without development of the LNG plant.

Table 7. Scenarios 2a and 2b Assumptions and Inputs

Upstream Production	2.1 million tonnes/ year for 25 years
BC natural gas price	$3.77/mcf
Regular royalty regime average rate	12.7%

Note. Data for scenarios 2a and 2b from BC Ministry of Finance, 2018.

Chapter 5. Results

5.1. Quantitative Analysis

Scenario 1a

In Scenario 1a, the Woodfibre LNG plant is developed and generates incremental government revenue from the LNGIT, provincial CIT, property tax, and upstream natural gas royalties under the LTRA. The regular natural gas royalty regime does not apply in Scenario 1a, as it is replaced by the LTRA. Three potential export prices were used in this analysis: the $13.50 CAD/mcf reference export price, the $11.50 /mcf low export price, and the $16.50/mcf high export price. At the reference export price, the LNG plant capital costs are paid off in 10 years and the total profit of the plant is approximately $1.18 billion over its 25-year lifetime. From this, the Province receives $592 million in incremental revenue (as shown in Table 9). At the low export price, the plant does not recover its capital costs and incurs a deficit of approximately $3.36 billion over the 25-year period. At the low price, the Province still receives of $410 million of incremental revenue from the plant (as shown in Table 9), though this scenario is rather unlikely as will be discussed later. At the high export price, the capital costs are paid off in 4 years, the total profit generated by the plant is approximately $9.01 billion over the 25-year period, and the Province receives approximately $1.56 billion of incremental revenue (Table 9).

The amount of revenue generated at each export price can further be analyzed by disaggregating the revenue by fiscal mechanism. Since the low export price results in the Woodfibre LNG plant running a deficit of $3.36 billion over the 25-year period, it is very unlikely that the plant would be developed unless investors assumed that prices would increase over time. If the plant was developed and operated at this price, the Province would only collect revenue from upstream natural gas royalties under the LTRA and property taxes. At the reference export price, upstream natural gas royalties under the LTRA generate $1.2 billion, 82% of the total revenue, and the CIT and LNGIT generate $126 million and $56 million respectively, 8% and 4% of the total (

Table 8 and Figure 4). The absolute values are summarized in

Table 8. CIT and LNGIT revenues are relatively low at the reference price due to the high capital costs of the project and the CCA depreciation deductions. The CIT and LNGIT do not generate revenue until the tenth year of operation. Also, the CIT revenues are decreased by the natural gas tax credit, which decreases the provincial CIT rate by 3%. The LNGIT revenues are low due to the design of the tax. As previously discussed, the tax only collects 1.5% of the plant's net profits until the capital costs of the plant have been recovered, which occurs in the sixteenth year of operation. The taxes paid at this rate are then deducted from the taxes owed at the 3.5% rate, which applies once the capital costs have been recovered.

At the high export price, the distribution changes significantly with the CIT and LNGIT generating $774 million and $379 million respectively, collectively making up close to half of the total revenue (Figure 4). The CIT and LNGIT begin to generate revenue in the second year of operation, and the 3.5% LNGIT rate commences in the fifth year of operation and generates $380 million over the 25-year period.

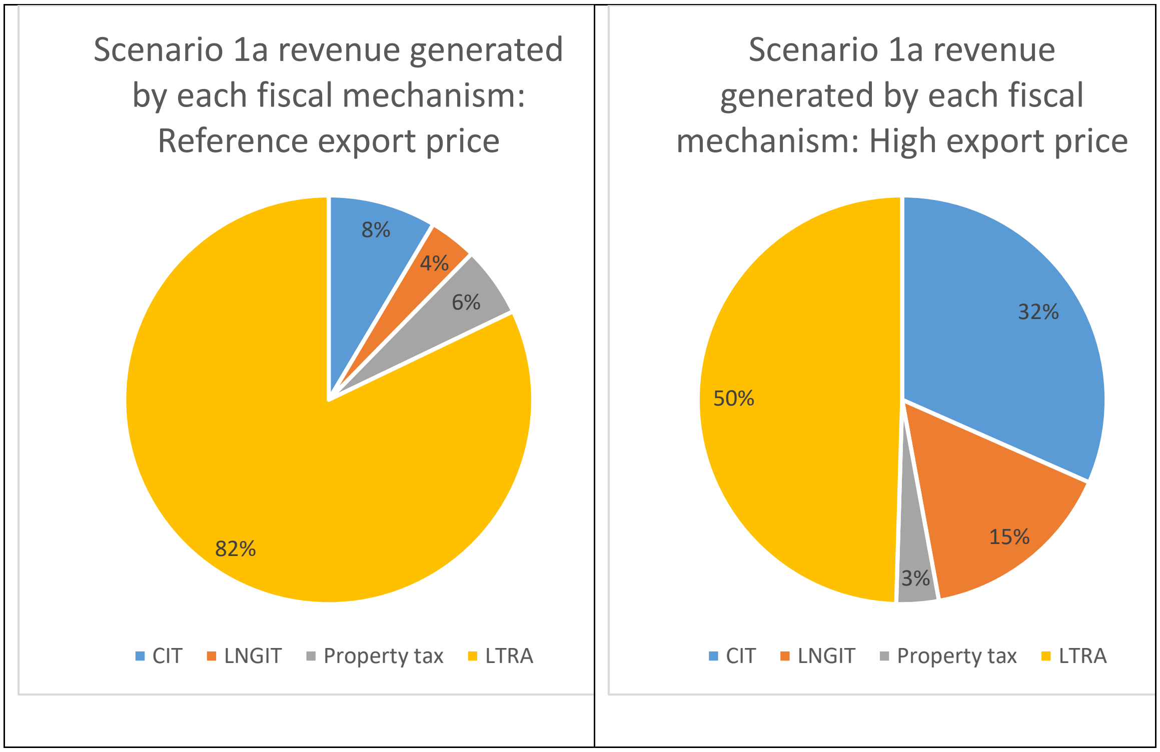

Figure 4. Disaggregation of percentage of total revenues by fiscal mechanism.

Table 8. Disaggregation of total revenues by fiscal mechanism

Scenario	LTRA (Million)	CIT (Million)	LNGIT (Million)	Property tax (Million)	Regular natural gas royalties (Million)	BC Hydro Subsidy (Million)	Total (Million)
Scenario 1a Ref	$1,212	$126	$56	$82	N/A	-$884	$592
Scenario 1a High	$1,212	$774	$379	$82	N/A	-$884	$1,563
Scenario 1b Ref	$1,212	$126	N/A	$82	N/A	-$884	$536
Scenario 1b High	$1,212	$774	N/A	$82	N/A	-$884	$1,184
Scenario 2a	N/A	N/A	N/A	N/A	$1,283	N/A	$1,283
Scenario 2b	N/A	N/A	N/A	N/A	$642	N/A	$642

Scenario 1b

Scenario 1b differs from Scenario 1a in that it does not include the LNGIT, which was recently eliminated by the current provincial government in April 2018 (Government of BC, Office of the Premier, 2018). It does, however, still include provincial CIT, property tax, and upstream natural gas royalties under the LTRA. Like Scenario 1a, the regular royalty regime does not apply in Scenario 1b as it is replaced by the LTRA. At the reference export price, the Province receives incremental revenue of approximately $536 million over the 25 years, $56 million less than Scenario 1a (Table 9). At the low export price, the Province receives incremental revenue of $410, equal to Scenario 1a. At the high export price, the Province receives approximately $1.2 billion of incremental revenue, $379 million less than Scenario 1a.

Scenarios 2a and 2b

In Scenario 2a, LNG is not developed and the natural gas is sold to non-LNG markets. Revenues in Scenarios 2a and 2b are only generated by the regular natural gas fiscal regime. In Scenario 2a, the Province receives approximately $1.3 billion over the 25-year period. In Scenario 2b, which assumes that less natural gas is produced as a result of LNG not being developed (equal to 50% of the supply to Woodfibre plant), the Province generates approximately $642 million of revenue (Table 9).

Table 9. Estimated Provincial Revenues by Scenario over 25 years (undiscounted millions of 2018 CAD)

Scenario	Reference Export Price (Million)	Low Export Price (Million)	High Export Price (Million)

1a	$592	$410	$1,563
1b	$536	$410	$1,184
2a	$1,283	$1,283	$1,283
2b	$642	$642	$642

Scenarios 1a and 1b vs Scenario 2a

While both Scenarios 1a and 1b generate revenue for BC, it is crucial to compare these revenues to the alternatives, Scenarios 2a and 2b, to assess the impact of LNG development on provincial revenue. The comparison between Scenarios 1a and 1b vs 2a simulates a direct shift of upstream production from supplying tradditional markets to supplying the LNG industry. In this comparison, it is assumed that the development of LNG would have no effect on upstream natural gas production.

The results show that in nine of the twelve scenarios, the Province receives less revenue by developing LNG than it does by not developing LNG and selling natural gas to traditional non-LNG markets. These results are shown in Table 9. The net revenue reduction varies between $50 and $873 million depending on the scenario. The reason the Province collects less revenue is that developing LNG generates incremental revenue through the CIT, the LNGIT, and property tax; but this incremental revenue is not enough to offset the revenue loss from the reduction in upstream natural gas royalties, resulting from the replacement of the current provincial royalty regime with the LTRA. Although the LTRA is meant to apply to new upstream natural gas production, it is unlikely that the development of the Woodfibre plant would be directly linked to an increase in upstream natural gas production due to its relatively small output of LNG. It is more likely that the Woodfibre plant would be supplied by new wells, for which the LTRA would still be applicable, that would be developed regardless of LNG development.

The only LNG development scenarios in which the Province could generate more incremental revenue than selling natural gas to traditional markets are three of the four high export price scenarios. The net increase in provincial revenue in these three scenarios ranges from $279 to $921 million. The reason for this is that the incremental CIT and LNGIT revenues from the higher profits of the LNG plant in Scenario 1a, resulting from the high export prices, are enough to offset the revenue losses resulting from the upstream royalty reductions under the LTRA. These high export price scenarios, however, are unlikely considering that natural gas prices in Asia are not projected to reach, let alone average, $16.50 in the next 12 years (World Bank, 2017). Further, Scenario 1a is unlikely because the LNGIT no longer exists and is unlikely to be reintroduced (Government of BC, Office of the Premier, 2018).

Scenarios 1a and 1b vs Scenario 2b: 50% lower production

The revenue generated in Scenario 2b assumes that natural gas production will be reduced to by 50% of the supply to the LNG plant. In other words, less natural gas is produced in Scenario 2b as a result of LNG not being developed (equal to 50% of the natural gas being supplied to the Woodfibre plant). The comparison results are shown in Table 10. It is only at the high export prices that the LNG scenarios generate more revenue than the non-LNG scenarios. At the high export price, the incremental CIT revenue generated in Scenario 1b (without the LNGIT) is high enough to offset the lower natural gas royalty rate under the LTRA. If LNG exports received a high price, however, it is rather unlikely that there would be incremental upstream natural gas production. A more likely scenario is that the development of an LNG plant and high export prices would create a shift production from supplying traditional markets to supplying the LNG plant.

Table 10. Comparison of Estimated Provincial Revenues (undiscounted millions of 2018 CAD)

Scenario	Reference Export Price (Million)	Low Export Price (Million)	High Export Price (Million)
1a-2a	-$692	-$873	$279
1a-2b	-$50	-$232	$921
1b-2a	-$747	-$873	-$100
1b-2b	-$106	-$232	$542

5.2. Interviews

A major finding of the interviews is that the informants that elected to evaluate the LNG-related fiscal policies and regime (5 of the 6 informants) were highly critical. These informants believed that the policies were neither reasonable nor effective, and pointed out major deficiencies. According to the informants, the policies are not the most appropriate policies for generating economic benefits for BC. The natural resource economic experts believe that the policies heavily favoured industry, and potentially the buyers in Asia, at the expense of BC residents. One expert stated:

> I don’t know if the tax regime makes any difference at all. I find it hard to see it raising any money, certainly not for the first decade or two. And again, there is a lot of uncertainty in global energy markets in terms of straight up pricing but also in terms of how we deal with climate change and whether those things make sense in the long term. It seems to me that there is a lot of effort going into place and the winners are customers in Asia that would be buying gas (Interviewee #1, 2017).

The critical evaluations made by the informants are supported by the results of the analysis performed in this study. Not only are incremental government revenues deferred due to the design of the fiscal regime, but in most scenarios BC will receive less revenue from LNG development under the new LNG fiscal regime than from selling natural gas to traditional markets. The provincial government representative that was interviewed declined to evaluate the policies since they are not currently being used in practice.

In addition to the results of the analysis performed in this study, the informants discussed various characteristics of BC’s LNG fiscal regime that support their critical evaluations stated during the interviews. One characteristic is that there are multiple objectives associated with LNG fiscal policies and the overall fiscal regime. For the LNGIT, multiple informants stated that the primary objective of this policy is to collect the rents associated with the price differential between North America and Asia. All informants acknowledged that the development of LNG should benefit the residents of BC. The primary objective behind the creation of the natural gas tax credit that applies to LNG plants, as asserted by a natural resource economic expert and an industry representative, is to decrease the tax burden and increase the competitiveness of LNG in BC.

The first objective behind the creation of the LTRA, as asserted by various informants, is to provide stability and certainty in natural gas royalty rates for industry and reduce the complexities associated with royalty payments. A government representative explained that since these LNG projects would involve substantial capital investments, industry's main request during the LTRA negotiations was for long-term stability in royalty rates. According to the government representative, industry did not want the government to be able to make changes to these royalty rates soon after the project had begun development. The second objective associated with the creation of the LTRA, according to the government representative, is to increase the upstream production of natural gas and therefore increase natural gas royalty revenue by accessing new markets. As the government representative explained:

> It was a way of increasing production in the upstream, directed to a clear source of demand. It wasn't about somebody saying “oh I want to sell more to Quebec.” No, this is about new sources of demand. So not establishing new royalty rates for the market that you have been sending or producing gas forever. It is new stuff that adds value according to what the legislation and regulations lets us do (Interviewee #3, 2017).

According to the natural resource economic experts, a major objective of the overall LNG fiscal regime, and the various concessions made in the design, is to ensure the that LNG industry is developed in BC. The natural resource economic experts stated that the main influence of this objective was political pressure. The experts asserted that their critical evaluations are further supported by the negative role that political pressure played in the development of the LNG fiscal regime. As one expert explained:

> The government made a commitment to develop LNG during the political campaign and so it felt very strong pressure to have at least one and up to three LNG plants being developed or in operation by the 2017 election. So, given that it was committed to doing that, it was under pressure to provide increasing degrees of incentives to the industry, and one of those was reducing the [LNGIT] rate from 7% to 3.5%. Then they also introduced a natural gas tax credit and a special royalty rate for the natural gas sector that was selling natural gas to the LNG sector (LTRA). All of these things combined reduce the financial burden on the LNG investors to try to ensure that they would undertake investments in British Columbia within the time frame set by the government (Interviewee #6, 2018).

A second characteristic of the fiscal regime that supports the critical evaluations relates to the relationship between public policy and natural resource management. All informants acknowledged the fact that natural gas, and LNG, are publicly owned natural resources, and therefore should be managed in a way that benefits all residents of BC. In 2013, the provincial government stated that "[i]t is in the public interest to save a large proportion of new LNG revenues through the B.C. Prosperity Fund," (Government of BC, Office of the Premier, 2013, p. 2). The informants stated that it is unclear, however, how it was determined that the revenue generated by LNG development was in the public interest, and how the LNG fiscal regime would achieve this objective.

Additionally, the informants stated that the process followed to create the policies lacked transparency and public input. According to the government representative, many analyses that allegedly supported the complete LNG fiscal regime, and how the fiscal mechanisms interacted with one another, were not made public since they contained financially sensitive information that the private companies did not want disclosed. The economic experts asserted that there was no opportunity for public input while these fiscal policies were being developed. On the other hand, multiple informants stated that there was a significant amount of interaction between the provincial government and industry while these economic policies were being developed, namely the LTRA. As one natural resource economic expert explained:

> As far as I can tell the only communication government had was with industry, and they met all the time. My colleague has been leading a project that is looking at lobbying and political donations of fossil fuel companies, and these guys met all the time. Either with the companies themselves or the industry trade associations. They would meet in Victoria, they would fly to Asia, and they were in constant contact. Arguably the BC government was working much more in the interest of the company than it was the people of British Columbia (Interviewee #1, 2017).

Only a few reports were made public: the government-commissioned revenue forecast reports (Ernst & Young, 2014; Grant Thornton, 2013), the signed LTRA between Progress Energy and the provincial government (BC Ministry of Natural Gas Development, 2015), and various government press releases that summarized each of the LNG-related fiscal policies.

A third characteristic of the fiscal regime that supports the critical evaluations is the interaction of the fiscal policies that make up the regime. The third-party natural resource economic experts stated that it is important to analyze how these policies interact when combined, rather than focusing on any fiscal policy in isolation. One expert explained:

> What you have to look at is the overall effect of this suite of policies on the revenues you are getting from this industry and your efficiency of

> capturing resource rents. But, at the same time not discouraging efficient development. And that is always a challenge in resource taxation (Interviewee # 2, 2017).

According to the provincial government representative, the ministries that developed the economic policies were not completely separate, but each had their own respective policy to focus on. Based on the interview with the government representative, it is unclear how much communication and coordination there was between ministries while these policies were developed. Also, it is uncertain whether the provincial government performed an analysis that included all the key economic policies because no such study was ever made public. The absence of this type of study being performed and made public supported the analysis in this study, since the results provide a more comprehensive evaluation of the complete fiscal regime.

A fourth characteristic of the fiscal regime that supports the critical evaluations, as explained by the informants, is that its design was influenced by competitor jurisdictions, especially Alberta. The informants asserted that Alberta is viewed as a natural gas competitor by the BC provincial government, especially with regards to the LNG industry. The government representative stated a concern that if the LNG-related fiscal mechanism rates are set too high, this will discourage LNG plants from purchasing BC natural gas. If this was the case, the government representative believes that LNG companies would look to Alberta natural gas companies to supply their plants. According to the provincial government representative, concerns regarding Alberta natural gas supported the development of the LNGIT. As the government representative explained:

> If you were interested in developing an oil and gas industry at all, you definitely need to make sure that you're still competitive. I think the new government has confirmed that they have a lot of interest in developing LNG and potentially other value-added opportunities. So, you know you need to have a competitive feedstock if you want to do that. If not, you might get an LNG plant but you might be exporting Alberta gas. Fill your boots if that's the way you want to go but you have to really take all those pieces into consideration. You want to do it to increase the value of the part that you're getting out of the Earth (Interviewee #3, 2017).

The informants that elected to evaluate BC’s LNG fiscal policies were quite critical and provided support for their assessments. The informants raised concerns regarding the multiple objectives of LNG development, stated the process used to develop the policies lacked transparency and appeared to have favoured industry, raised concerns associated with how the policies and mechanisms interact with one another, and asserted the design of the fiscal mechanisms was influenced by competitor jurisdictions. The critical evaluations made by the informants are further supported by the results of the quantitative analysis in this study, which show that under most scenarios BC will collect less revenue from the Woodfibre LNG plant than from continuing to sell natural gas to traditional markets. These findings are explored further in the following section.

Chapter 6. Discussion

6.1. Interviews

The findings of the interviews illustrate the tension among potentially conflicting objectives in LNG development. The Province promised a $100 billion Prosperity Fund that would ensure all residents of BC would benefit from LNG development.

But this objective has been compromised by increasing concessions to the LNG sector to try to ensure that LNG development proceeds. Faced with a weakening LNG market, the Province has made a series of changes to the LNG fiscal regime. The LNGIT was originally decreased from 7% to 3.5%, and then recently eliminated. The Province has made further concessions, including the natural gas tax credit on CIT, the BC Hydro eDrive subsidy, and the LTRA. As the natural resource economic experts asserted, the concessions made by the provincial government impact the Province's objective to "guarantee a fair return for BC's natural resources" (Government of BC, Office of the Premier, 2018, p. 1). As previously outlined, and revealed in the interviews, changes to the LNG fiscal regime appear to have been influenced by political pressure and undue optimism regarding the economic benefits associated with LNG development. This illustrates a principal challenge in LNG policymaking: how to manage trade-offs among conflicting objectives. At what point do changes to achieve one objective, such as fiscal concessions to ensure LNG development, pass a threshold and sacrifice achievement of other objectives, with the result that the development of an LNG industry is no longer in the economic interest of BC? The natural resource economic experts speculate that the fiscal concessions may have crossed this threshold. As one natural resource economic expert explained:

> I think the LNG income tax was a means of trying to capitalize on [the price differential] and came at a time when the price of gas was very high. Then later on the price in Asia started to drop in 2015. Those profit margins became no longer profitable for the company, so as the process rolled on and the government ended up caving on a lot of the promises of

> the LNG income tax. I think at the end of the day the overall tax regime they're putting in place for LNG is probably worse than the existing corporate income tax regime (Interviewee #1, 2017).

The interview informants also emphasized the importance of the LNG development policymaking process being transparent and comprehensive. This aligns with the best practices for fiscal mechanism development as discussed by the OECD (2018), Tilton (2004), and Weijermars (2015). The natural resource economic experts were critical that the process used to develop the LNG-related fiscal policies did not allow for any public input and did not provide detailed information to the public on the evaluation of alternative policies and fiscal mechanism designs. For comparative purposes, the provincial environmental assessment process that was conducted to assess the environmental impacts associated with developing the LNG plants did allow for public input. For the Woodfibre project, the public had the opportunity to submit letters during the application development phase and the application review phase, as well as submit comments after the environmental assessment certificate was issued (BC Environmental Assessment Office, n.d.). As discussed by the informants, the LNG fiscal policy development process did include significant input from the LNG companies. Any concessions or fiscal policies that increase the economic benefits retained by industry likely do so at the expense of BC residents since most of the higher profile LNG proponents in BC are based in foreign countries.

The informants were concerned that the evaluation of options was not comprehensive enough. As discussed by the OECD (2018), Tilton (2004), and Weijermars (2015), developing an optimal fiscal regime is highly complex and requires a significant amount of modelling exercises and negotiations between the operator and the government. Individual fiscal proposals may have been evaluated independently from each other with no analysis of how the various proposals interacted. No such analysis was ever made public. The natural resource economic experts stated the importance of evaluating the overall fiscal regime to assess the impact, as opposed to policies in isolation. Evaluating the overall LNG fiscal regime allows for a proper comparison between a scenario in which LNG is developed and a scenario in which LNG is not developed (as seen in the quantitative analysis). Additionally, it allows for an analysis of how the policies interact with one another. If the current LNG fiscal regime is neither reasonable nor effective, then it is unlikely that the Province's goals and objectives regarding earning a fair return for residents of BC will be achieved.

6.2. Quantitative analysis: Comparison with other studies

Table 11. Comparison of estimated incremental government revenue resulting from LNG development in BC

Report	Million CAD/million tonnes LNG (2018 CAD)
Ernst & Young (2013)	$51.7 - $100.8
Grant Thornton (2013)	$85.6 - $121.5
Lee (2014)	$24.1 - $40.2
Woodfibre (n.d.)	$43.3
Gunton (2018) 1b	$10.2 - $22.6
Gunton (2018) 1b-2a	-$14.2 - -$1.9
Gunton (2018) 1b-2b	-$2.0 - $10.3

The results of this study are compared to the provincial government-commissioned reports, completed by Ernst and Young (2013) and Grant Thornton (2013), Lee's (2014) report, and the revenue estimates prepared by Woodfibre LNG (n.d.) (Table 11). For Ernst & Young's (2013) and Grant Thornton's (2013) reports, revenue estimate ranges are based on differences in LNG export prices, natural gas prices, capital and operating costs, production volume, capital structures, and capital depreciation rates. Lee's (2014) revenue estimate range is based on differences in LNG export prices and production volumes. The results show that my revenue estimates are significantly lower than those provided in these other studies. Additionally, the results indicate that the Woodfibre LNG plant will generate less incremental government revenue than estimated by the proponent. Woodfibre LNG (n.d.) estimates that the plant will generate approximately $91.0 million (converted into 2018 CAD) of incremental government revenue per year, or $43.3 million per million tonnes of LNG. Unlike the other revenue estimates, Woodfibre LNG's (n.d.) estimate includes federal government revenue. When just looking at the incremental revenue generated by the Woodfibre LNG plant, my analysis indicates an average of $21.4 million of revenue per year, or between $10.2 million and $22.6 million (Scenario 1b reference export price). When comparing to a scenario in which LNG is not developed, however, my analysis indicates that the Woodfibre LNG plant will generate on average -$29.9 million of incremental government revenue per year, or between -$14.2 million and -$1.9million per million tonnes of LNG (Scenario 1b reference export price). This, again, is because in most scenarios the

Province will generate more revenue by selling natural gas to traditional markets and not developing LNG.

The difference between my revenue estimates and those estimated by Grant Thornton (2013), Ernst & Young (2013), and Lee (2014) can primarily be attributed to the sources of revenue used in each study and the assumptions regarding natural gas production and royalties with and without LNG. Woodfibre LNG (n.d.) does not provide the assumptions or inputs for its revenue estimates, and therefore I cannot comment on why my revenue estimates are different. The Grant Thornton (2013) and Ernst & Young (2013) studies included CIT, personal income tax (paid by employees), PST, natural gas royalties, and the LNGIT (using the 7% rate). As previously discussed, some tax revenue generated by a project, including revenues generated by personal income taxes and PST, is needed to cover incremental project costs, such as providing government services to employees, and therefore is not incremental revenue (Shaffer, 2010). Lee’s (2014) study includes the LNGIT (using the 7% rate), CIT, and natural gas royalties as sources of revenue. All three of these studies use the higher LNGIT rate in their analyses since they were completed before the 3.5% rate was put into legislation. For CIT, the Grant Thornton (2013) and Ernst & Young (2013) studies use the 11% provincial rate without applying the proposed natural gas tax credit. Lee’s (2014) study, on the other hand, does apply a lower CIT rate by using the average deduction rate, bringing the CIT rate down to between 8% and 9%.

All three of the studies; Ernst & Young (2013), Grant Thornton (2013), and Lee (2013); assume that natural gas supplied to the LNG plants is incremental production. In my analysis, the revenue generated by LNG development is compared to the revenue generated by the natural gas industry without LNG. This results in the negative revenues seen in Table 11, since more government revenue is generated by selling natural gas to traditional markets. For the natural gas royalties, these studies use royalty rates applied under the regular royalty regime rather than the lower rates applicable under the LTRA. Additionally, the revenue estimates by Grant Thornton (2013), Ernst & Young (2013), and Lee (2014) are likely higher since they do not account for the incremental costs associated with the provision of the BC Hydro eDrive subsidy.

This comparison shows that there can be a wide range in revenue estimates for LNG development depending on the assumptions used. The implications of these differences in revenue estimates will be discussed in the conclusion section.

6.3. Limitations of Quantitative Analysis

The quantitative analysis conducted in this study has some limitations. One limitation is that the two models that were used in this analysis are not designed to calculate an optimal LNGIT rate for a desired amount of revenue since the tax rate is an exogenous variable that is inputted by the user. Calculating the optimal tax rate would be useful for providing recommendations on a more effective fiscal regime. A second limitation of this study's analysis is that it was assumed that

LNG development would not affect natural gas prices. Given the small production volume of the Woodfibre LNG plant relative to the North American gas market that BC is integrated into, this is a reasonable assumption. However, the LNG export sector could eventually become large enough to impact BC natural gas prices. If LNG was developed and earned a higher price than domestic natural gas sales in the short run, natural gas producers would likely shift their supply to LNG plants. In the long run, this shift in supply would increase domestic natural gas prices until they were in equilibrium with LNG export prices and producers were indifferent as to which market they supplied. This impact has been seen in Australia, where domestic gas prices have increased as a result of LNG development (Ryan, 2017). If this happened in BC, additional analyses would be required to model the impact of LNG development on natural gas prices and to assess the impact of these prices changes on provincial government revenue. A third limitation of this study's analysis is that it only focused on revenue impacts and not on the environmental or social impacts associated with LNG development. A fourth limitation is that different financing structures, such as debt versus equity and the cost of borrowing, were not considered in this analysis. Taking on debt in the form of loans to fund the LNG project would likely impact the profitability of the project, resulting in decreased government revenue. This likely resulted in overestimations of the taxable income generated by the Woodfibre LNG plant, and consequently overestimations of the government revenue generated by LNG development.

Chapter 7. Conclusion

The purpose of this study is to analyze how BC will benefit from the new LNG fiscal regime. This was achieved by addressing four key sub questions: 1. What are the relevant LNG economic policies that make up the fiscal regime in BC? 2. What process was followed to develop the fiscal policies and overall fiscal regime? 3. What is the incremental government revenue that can be expected from the Woodfibre LNG plant as a result of the new LNG fiscal regime? 4. How does the incremental government revenue from the Woodfibre LNG plant compare to the revenue generated by the natural gas industry under BC's current natural gas royalty regime?

Four key methods were used to answer these research questions. First, I conducted a literature review to obtain general and contextual information on Canadian resource policy, global LNG development, best practices for natural resource fiscal mechanism development, and the goals and objectives of LNG development in BC. Second, I performed a document analysis to identify the relevant policies that make up BC's LNG fiscal regime. Third, I conducted key informant interviews to learn about the process that was followed in developing the policies, what the objectives of the policies are, and how the policies are evaluated by experts. Additionally, information obtained in the interviews was used to support the quantitative analysis in this study. Fourth, I conducted a quantitative analysis to estimate the government revenues that would be generated in various LNG development scenarios, and then compared these estimates to the estimated revenues that would be generated if LNG was not developed in BC.

The results of my quantitative analysis show that due to the design of the LNG fiscal regime, it is unlikely that LNG development will generate fiscal economic benefits for the Province. Under most scenarios, BC would generate less revenue from developing LNG than from selling natural gas to traditional markets. The scenarios in which the Province would generate more revenue from LNG development are highly unlikely and would require prices to significantly increase in Asia. The provincial government revenue estimates from this study are much lower than the revenue estimates from the provincial government-commissioned reports, completed by Ernst & Young (2013) and Grant Thornton (2013), Lee's (2014) report, and the revenue estimates prepared by Woodfibre LNG (n.d.). As previously discussed, these studies were methodologically deficient. The Ernst & Young (2013) and Grant Thornton (2013) studies included non-incremental sources of revenue and the previously proposed rates for the LNGIT and CIT. Lee's (2014) study also used the previously proposed LNGIT rate, as it was completed before the tax was enacted. All three of these studies assumed the natural gas supplied to the LNG plants would be incremental and did not have an opportunity cost based on its consumption in other non-LNG markets. Additionally, none of these studies included the costs associated with applying lower royalty rates under the LTRA or the provision of the BC Hydro eDrive subsidy.

The results of quantitative analyses, such as the one conducted in this study, largely depend on the assumptions and inputs used. Although there are uncertainties associated with the results of this study, this is the type of analysis that needs to be completed to support the development of public policies relating to natural resource development. It is unclear whether the provincial government ever performed this type of comprehensive analysis, as no such study was ever made public. Not transparently providing adequate support for the development of BC's LNG fiscal regime or allowing for public input contradicts best practices in equitable agreement development (OECD, 2018; UN, 2016; Weijermars, 2015). Admittedly, the analysis conducted in this study is just one component of assessing the overall benefits and costs of developing LNG in BC and needs to be complemented by other analyses evaluating all the other characteristics of LNG development, including the environmental and social impacts (Shaffer, 2010). An evaluation of the fiscal regime is, however, an essential component of the overall evaluation process.

The results of the quantitative analysis and the key informant interviews are evidence that there is tension between the objectives of the LNG economic policies. Keeping BC LNG competitive in the global market, and ensuring LNG is developed, conflicts with the objective of obtaining a fair return for the residents of BC. As previously discussed, finding the balance between a soft fiscal regime that does not adequately collect the economic rent of a natural resource and a stringent fiscal regime that deters development is a complex and difficult task (Tilton, 2004; UN, 2016; Weijermars, 2015). As stated by the government representative, one of the goals behind the development of the new policies, such as the LTRA, was to access new markets and increase upstream natural gas production. As previously discussed, it is unlikely that the development of LNG in BC would be directly linked to an increase in upstream natural gas production. It is more likely that the LNG plants would be supplied by new wells (for which the LTRA would still apply) that would be developed regardless of LNG development. As a result of the Province's goal to increase upstream natural gas production, and as stated by other informants, changes to the LNG fiscal regime appear to be more weighted towards keeping BC competitive, and developing the industry, than collecting the economic rent, which consequently means that BC is unlikely to collect incremental revenue associated with exporting LNG to Asia. This is supported by the quantitative analysis results, which show that the Province is unlikely to collect a significant amount of revenue, and the interview results, which show that the government worked closely with industry and largely left the public out of the process.

7.1. Recommendations

During the interviews, the key informants suggested multiple recommendations that would allow the Province to capture the rents associated with exporting LNG to Asia and generate revenue for BC. One recommendation, suggested by a natural resource economic expert and an industry representative, is to focus on collecting revenue from the LNG plants through the provincial CIT. Under the new LNG fiscal regime, the provincial CIT is decreased by up to 3%, from 11% to 8%, by the natural gas tax credit. The informants suggested that it would be more appropriate to increase the provincial CIT above the 11% rather than use an LNGIT. The natural resource economic expert stressed that if this method was used, precautions would need to be taken to protect against transfer-pricing scenarios that shift the tax burden to foreign countries with lower CIT rates.

A second recommendation suggested by the informants is to capture the rent at the wellhead and focus on collecting royalties from upstream natural gas extraction, and potentially increase the royalty rate, under the regular royalty regime. The informants stated, however, that this method would only work if the LNG plants were supplied by BC gas, and would be negated if the plants were supplied by Alberta gas.

A third recommendation made by the informants is that if the provincial government wanted to use the LNGIT, the design could be changed to increase government revenue. One natural resource economic expert suggested that a Rate of Return Royalty would be better suited to collect rent on LNG exports and would not deter investment by levying tax payments when prices fall below a certain threshold. A second natural resource economic expert suggested eliminating the ability for LNG plants to defer LNGIT payments by amortizing capital costs over a long period of time.

A fourth recommendation, made by a natural resource economic expert, is that if the Province was insistent on developing LNG in BC, the government could start a Crown Corporation. The expert stated:

> It seems to me like a lot of this is based on big global companies and trying to court to them to make large investment decisions in BC. If it was really that profitable, there's no reason that the BC government could not have done it itself through a Crown corporation. That would be an alternative way of doing things and it's not uncommon in other parts of the world to have state-owned enterprises managing the extraction, processing, and production of their exported fossil fuels (Interviewee #1, 2017).

A fifth recommendation, which was made by a representative of a First Nation, is that the provincial government should focus on developing a few LNG plants, rather than dispersing time and resources among the 20 proposed plants. The informant explained that it was clear that not all 20 plants would be developed, and it would be more efficient and effective for the government to be strategic and focus on one or two projects. Additionally, the same informant stated that the government should adopt a more collective and collaborative engagement process that incorporates First Nations and all stakeholders, instead of keeping interactions and negotiations between all groups separate.

My recommendations relate directly to the results of this study. The process used to develop the LNG fiscal regime should be much more inclusive. As discussed previously, the provincial government has the fiduciary responsibility to develop a fiscal regime that balances the interests of all parties affected by the fiscal regime (OECD, 2018; UN, 2016; Weijermars, 2015). Fulfilling this responsibility requires the provincial government to not only negotiate with private companies but to also include the public in the decision-making process, as this would help build trust and buy-in (UN, 2016). Additionally, government decisions regarding the LNG fiscal regime should be defensible and transparent. The provincial government should conduct a comprehensive analysis that clearly shows how the revenue generated by the LNG fiscal regime compares to alternative regimes and resource sectors (European Commission, 2017; Office of the Auditor General of Manitoba, 2003), such as the analysis in this study. This study should clearly show how the LNG fiscal regime, and the development of LNG, is in the public interest of BC.

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Appendix

Key Informant Interview Guide

LNG Income Tax

Process

- What criteria were used and what do you think the objectives were when developing the LNG Income Tax?
- How was the decision made to use this particular type of income tax as opposed to a different type of tax?
- What role did industry play in shaping the LNG Income Tax?
- What role did the public play in shaping the LNG Income Tax?

Analysis

- What type of analysis was performed to support this type of taxation mechanism?
- Is this information publically available?
- Were alternative taxation mechanisms considered?
    - If not, why not?
- What studies were used to assess alternatives/ tax or royalty used?
- Were taxes/royalties used by other jurisdictions considered when making the decision?
    - If not, why not?
    - If yes, what did comparisons show?

Rationale

- Why did the LNG income tax rate on net income change from 7% (when first proposed) to 3.5%?
- Why does the LNG income tax rate on net income change from 3.5% to 5% in the year 2037?

Evaluation

- Do you think the LNG Income Tax that was put into place is reasonable and effective?
    - The best possible tax for maximizing returns to the province and developing the LNG industry?
    - Does it have any deficiencies?
    - What could be improved/how could the deficiencies be best addressed?

- What do you believe will be the outcome of these changes on the province’s revenue?

Natural Gas Tax Credit (Corporate Income Tax decrease)

- What is the purpose of and what do you think the objectives were when developing the natural gas tax credit?
- Why was the Natural Gas Tax Credit increased from 0.5% to 3% for of the cost of natural gas purchased for liquefaction activities? What is the goal of this change?
- What do you believe is the net revenue impact when the LNG Income Tax (3.5%) is coupled with the Corporate Income Tax decrease (3%)? (Does the decrease in the corporate income tax offset the LNG income tax?)

Long Term Royalty Agreement

Process

- What criteria were used and what do you think the objectives were when developing the Long-term royalty agreement?
- How was the decision made to use this particular type of royalty regime as opposed to a different type of royalty regime?
- What role did industry play in shaping the Long-Term Royalty Agreement?
- What role did the public play in shaping the Long-Term Royalty Agreement?

Analysis

- What type of analysis was performed to support this type of royalty regime?
- Did the provincial government do any studies looking at the net revenue result of all three of the royalty and tax changes? (LNG Income Tax, natural gas tax credit, and long-term royalty agreement?
- Is this information publically available?
- Were alternative royalty regime considered?
    - If not, why not?
- What studies were used to assess alternative royalty regimes used?
- Were royalty regimes used by other jurisdictions considered when making the decision?
    - If not, why not?
    - If yes, what did comparisons show?

Rationale

- What is the purpose of the Long-Term Royalty Agreement?
- Why are the royalty rates relatively predetermined?

Evaluation

- Do you think the Long-Term Royalty Agreement that was put into place is reasonable and effective?
  - The best possible royalty regime for maximizing returns to the province and developing the LNG industry?
  - Does it have any deficiencies?
  - What could be improved/how could the deficiencies be best addressed?
- What do you believe will be the outcome of these changes on the province's revenue?