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Prospects for Exporting Liquefied Natural Gas from British Columbia: An Application of Monte Carlo Cost-Benefit Analysis

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Prospects for Exporting Liquefied Natural Gas from British Columbia: An Application of Monte Carlo Cost-Benefit Analysis

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Abstract:

British Columbia's natural gas industry is currently facing competitive pressures from other gas-producing jurisdictions in North America. The emergence of shale gas developments has resulted in natural gas prices falling dramatically. Nonetheless, British Columbia is positioned to take advantage of growing markets in Asia that have considerably higher prices than in North America through the export of liquefied natural gas (LNG) in carrier ships. This paper aims to assess the economic viability of an LNG industry in British Columbia by analyzing world LNG prices and trade, market development, and costs through a Monte Carlo risk assessment.

Keywords: LNG trade, natural gas as coal replacement, Monte Carlo simulation, shale gas

JEL categories: Q37, Q41, Q42 and Q48

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1. INTRODUCTION

The natural gas industry in North America changed dramatically in 2008 when improvements in technologies for extracting gas from shale rock plays became economically viable. The application of hydraulic fracturing and horizontal drilling allowed exploration and production firms to access massive natural gas reserves in North America, resulting in changes in the distribution of supply on the continent. This increase in reserves and production also resulted in lower natural gas prices.

In British Columbia, this shale gas revolution has been both a benefit and a detriment to the natural gas industry. The province saw a massive increase in its gas resources and production, but at the same time now faces competitive pressure due to the lower gas price and large distances from North American markets compared to other plays.

Natural gas exploration and production is an important industry in British Columbia, particularly in the northeast of the province. In the 2011/12 fiscal year, the natural gas industry contributed an estimated $367 million in royalty revenue to the province of British Columbia, in addition to land and tenure sales, carbon taxes, corporate taxes and a multitude of indirect economic impacts (Province of British Columbia, 2012, p. 16). With the province's vast natural gas plays only now at the start of their development, it is expected that economic growth and natural gas royalties will increase into the future (Province of British Columbia, 2012).

Several liquefied natural gas (LNG) projects have been proposed (see Appendix 1), presenting British Columbia with an opportunity to export LNG to alternative markets in Asia that have considerably higher gas prices than North America. However, investments in LNG facilities require large capital expenditures and long timelines for cost recovery, making investment in LNG projects a high-stakes venture.

This paper aims to assess the economic viability of an LNG industry in British Columbia by analyzing costs, world LNG prices and trade, and potential future market developments. A Monte Carlo risk analysis is employed to consider the opportunity, risk and uncertainty of LNG facility investments in British Columbia.

I begin in the next section by providing background information on LNG and describing the potential markets that could be accessed from British Columbia. In section two, the cost model and Monte Carlo approach are discussed, followed in section three by a discussion of the data used in the simulation. Section four presents the results of the Monte Carlo simulation of LNG costs and prices in British Columbia. The conclusions from the analysis are presented in the final section of the paper.

2. BACKGROUND

This section of the paper provides the context of the study. LNG and the liquefaction process, the history of the LNG industry, and market conditions – LNG demand, supplying facility capacity from exporting countries, and prices – are briefly explained. The focus of the study is on the Asia Pacific region as the potential market for British Columbia LNG.

LNG and Process

To understand markets for LNG, an examination of the process and technology utilized is required. The process from exploration to end market is known as the 'LNG value chain' and consists of four phases:

1. Exploration and production;
2. Liquefaction;
3. Shipping; and
4. Storage and regasification.

As this study is specifically centered on the LNG process and not natural gas use, we examine only the second and third phases of the value chain. The first phase of the value chain is only considered as an input cost.

Liquefaction

While natural gas is usually transported in pipelines, it becomes very costly to do so over long distances, especially across oceans. An alternative is to liquefy the natural gas by cooling it to minus 161 degrees Celsius, which reduces the volume of the gas to approximately one six-hundredth of its original volume, and then transporting the liquefied gas by ship. This process makes it more efficient to transport natural gas over large distances and store it for long periods of time (Andersson et al., 2010). The components of a typical liquefaction plant are illustrated in Figure 1.

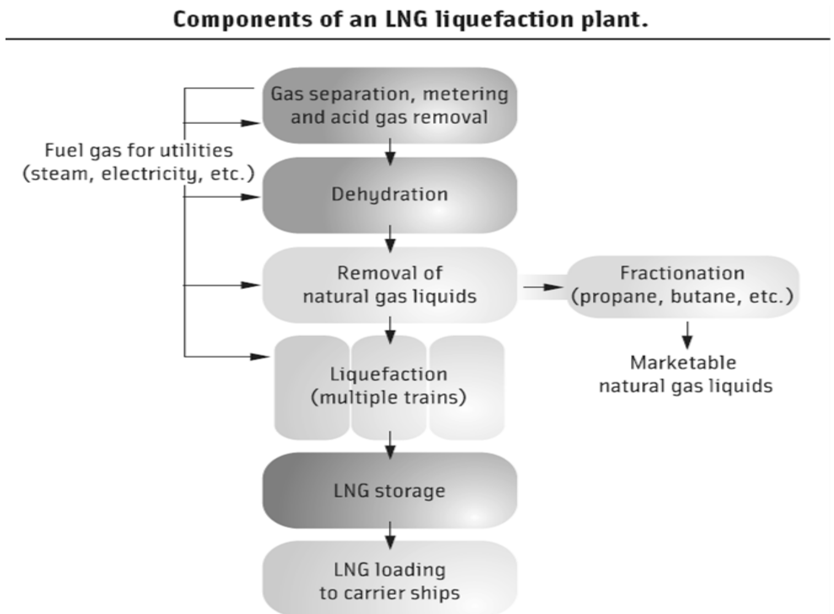

Figure 1: Steps in the LNG liquefaction process (U.S. Department of Energy, 2005, p. 11)

The raw feed gas that arrives from the field must be clean and dry, so it is scrubbed of hydrocarbons to remove trace amounts of hydrogen sulphide and carbon dioxide. In British Columbia, the gas used by LNG facilities will have to be transported though the existing pipeline transmission network, and thus will already have been processed to remove hydrogen sulphide and most of the carbon dioxide. A maximum of two percent carbon dioxide is permitted in the natural gas transmission network in North America according to the Energy Standards Board (TransCanada Pipelines Ltd., 2012). The processing actually occurs at a gas processing facility in Northeast British Columbia before reaching the LNG facility in Kitimat. The gas is then cooled in stages to minus 161 degrees Celsius to allow water and other liquids to condense and be removed.

There are a number of different technologies that can be used to cool the gas to a liquid. The evolution of turbine and compressor designs has led to steady decreases in the power required to liquefy natural gas. Once the gas is in liquid form, it is subject to boil-off losses, which amount to approximately 0.15 percent of the volume per day; this 'lost' gas provides energy to the liquefaction facility, ships and receiving terminals, until the LNG is heated into its natural gaseous state (DOE, 2005).

Shipping

There are two main designs for the tanks on the ships: a membrane design and a spherical design. Three quarters of new LNG carriers utilize the membrane design to increase cargo capacity, reducing costs and construction time. In May 2005, 181 LNG carriers were operating, with another 74 under construction for delivery in 2005-07. The LNG carrier capacity has grown significantly since then with 360 carriers operating in February 2013, and another 80 carriers under construction (Shipbuilding History, 2013).

Carrier ships are owned by LNG producers, LNG consumers or independent shipping companies. It is often the case that Japanese buyers, who require supply security at predictable costs, own the LNG carriers (DOE, 2005). I assume that LNG carriers are chartered at a per-day rate.

Regasification

Once the LNG is brought into a receiving terminal, it is regasified using ambient temperature systems that employ heat from surrounding air and sea water, while additional heat is added by burning fuel (DOE, 2005). Afterward, the natural gas is ready for market transmission or distribution through pipelines. In many cases, LNG is stored in order to meet consumption needs on cold winter days when gas consumption peaks, similar to the Fortis's Mt. Hayes LNG Peak Storage facility in Ladysmith (Fortis BC, 2007). Therefore, import terminals need to include tanks that store LNG for this purpose.

Other Considerations

Quality

Not all LNG is consistent in composition. While LNG consists of 87-97% methane, the remaining 3-13% can be made up of various amounts of ethane, propane, butane and nitrogen (DOE, 2005, p. 15). The composition affects the British thermal unit per standard cubic foot (btu/scf) and consequently the heating value of the natural gas. This is important since appliances and industrial processes rely on the flame produced by the gas to be within a specific temperature range, so the gas must be of the correct composition. There are some technologies available that can compensate for the impurities, but this can be costly; such technologies employ devices that inject air or nitrogen into the gas (DOE, 2005). This will not be a consideration for the LNG plants to be built in British Columbia, despite the lower heating value of the province's natural gas, because Asian buyers are still willing to purchase LNG from British Columbia (National Energy Board [NEB], 2011).

Safety

LNG transport is relatively safe, with no serious accidents in port or at sea in the past 40 years (DOE, 2005). The liquefied state of the natural gas reduces the risk of fire or explosion. LNG will not contaminate land or water resources and therefore requires no environmental clean up when spilled; for example, if LNG spills at sea, the fuel quickly vaporizes and does not produce a slick. LNG is not stored under pressure. An LNG explosion could not occur unless the liquid gas were to vaporize back to its gaseous state, collect in a confined space at five to 15 percent concentrations and then somehow be ignited (NEB, 2010). There have only been a couple of incidents that have resulted in explosions at LNG facilities in the technology's history.

History

Traditionally, LNG has been a very small component of the natural gas mix. In recent years, however, natural gas consumption has risen and LNG has become a larger component of consumption, due in part to high natural gas price differences across the globe and falling LNG liquefaction and transportation costs. As a result, there has been substantial worldwide investment in LNG production facilities, tankers, import terminals and gasification facilities (DOE, 2005).

The first LNG plant was built in 1964 in Algeria and LNG shipments began in that year to the UK. The second commercial LNG facility in Alaska began shipping to Japan in 1969 (Langton, 1994). Japanese imports increased into the 1970s and 1980s for gas-fired electricity generation to reduce pollution and relieve pressure from the 1973 oil embargo. Approximately 95% of Japan's natural gas demand is met by LNG imports, which currently account for nearly one third of world LNG trade (see Table 1). The U.S. started to import LNG from Algeria in the 1970s, and did so until the natural gas bubble of the 1980s reduced imports and led to the mothballing of several terminal facilities. Since the 1990s, natural gas demand has risen worldwide and the global LNG trade has increased in parallel with the demand growth (DOE, 2005).

LNG Demand

Worldwide consumption of natural gas is expected to continue to increase, with LNG playing a large role. The increase in consumption will be driven by a number of contributing factors (International Energy Agency [IEA], 2012):

1. Electric utilities are recognizing the lower capital costs, shorter construction lead times and lower emissions of natural gas electricity generation;
2. The residential sector is utilizing gas appliances due to the benefits associated with benefits from higher fuel efficiency and lower CO_2 emissions;
3. The industrial sector uses natural gas as feedstock or fuel for pulp, paper, metals, chemicals, fertilizers, fabrics, pharmaceuticals and plastics;
4. The transportation sector is beginning to see natural gas as a clean and readily available alternative to conventional fuels;
5. Asian natural gas prices are relatively high while access is limited to domestic supplies; and
6. Large shale gas reserves have led to lower natural gas prices in North America.

International LNG demand is centered on two geographic regions – the Atlantic Basin and the Pacific Basin in Asia. The Middle Eastern LNG exporting countries supply mostly Asian customers but also supply some gas to Europe and the United States (U.S.). The Pacific region generally observes higher prices, though U.S. prices can peak seasonally, attracting some LNG cargo (DOE, 2005).

The Asia Pacific Basin accounted for nearly half of LNG exports in 2003, while the Atlantic Basin accounted for 32%. By 2011, there were six LNG importing countries in the Asia Pacific basin – Japan, South Korea, India, China, Taiwan, and Thailand – accounting for 63% of world LNG demand and Atlantic Basin demanding the remaining 37%. Liquefaction capacity in both regions is increasing (BP Statistical Review, 2012).

Table 1: Asia Pacific LNG Import Volumes by Country (2011)

Importing Country	Natural Gas imported in 2011 (Million tonnes)	Percentage of World LNG Trade
Japan	77.5	32.3%
South Korea	35.8	14.9%
India	12.4	5.2%
China	12.05	5.0%
Taiwan	11.8	4.9%
Thailand	0.7	0.3%
Total Asia Pacific LNG Imports	**150.3**	**62.7%**

Source: BP Statistical Review, 2012

Table 2 displays the countries that exported LNG to the Asian Pacific region in 2011. Qatar is currently the leading exporter to Asia, with Australia expected to increase exports dramatically in the near future. There is also potential of LNG export growth from Russia and Malaysia (IEA, 2012).

Table 2: Pacific LNG Export Volumes by Country (2011)

Exporting Country	2011 LNG Exports (Mt) (% of world trade)	Importing Countries
Qatar	35.3 (14.7 %)	China, India, Japan, South Korea, Taiwan, Thailand
Malaysia	23.8 (9.9 %)	China, India, Japan, South Korea, Taiwan
Indonesia	20.9 (8.7 %)	China, Japan, South Korea, Taiwan, Thailand
Australia	18.6 (7.7 %)	China, India, Japan, South Korea, Taiwan
Russia	10.4 (4.3 %)	China, Japan, South Korea, Taiwan, Thailand
Oman	7.8 (3.3 %)	India, Japan, South Korea, Taiwan
Brunei	6.8 (2.8 %)	Japan, South Korea
UAE	5.7 (2.4 %)	India, Japan, Taiwan
Nigeria	5.5 (2.3 %)	China, India, Japan, South Korea, Taiwan, Thailand
Yemen	3.9 (1.6 %)	China, India, Japan, South Korea, Taiwan
Equatorial Guinea	2.9 (1.2 %)	China, Japan, South Korea, Taiwan
Trinidad & Tobago	2.7 (1.1 %)	China, India, Japan, South Korea, Taiwan
Egypt	2.2 (0.9%)	China, India, Japan, South Korea, Taiwan
Peru	1.5 (0.6 %)	China, Japan, South Korea, Taiwan, Thailand
U.S.	1.0 (0.4 %)	China, India, Japan, South Korea
Norway	0.7 (0.3 %)	India, Japan, South Korea, Taiwan
Belgium	0.3 (0.1%)	Japan, South Korea
Algeria	0.2 (0.1%)	India, Japan
Spain	0.2 (0.1 %)	Japan, Taiwan

Source: BP Statistical Review, 2012

LNG Prices

In most countries, LNG prices must be competitive with a local hub spot-market for natural gas. From the perspective of importing countries, domestic natural gas prices are the natural gas benchmark for making buying decisions, so companies will import LNG if prices are competitive with domestic prices. This implies that average LNG import prices follow domestic prices quite closely, taking into account the difference of LNG regasification costs, in countries that have competitive natural gas markets. Thus, we observe an increase in LNG imports as the domestic prices rises (DOE, 2005).

Asian markets are an exception to this trend as LNG prices are determined differently there than in most other regions of the world. In Asian countries there is no centralized hub for setting competitive prices, and LNG is the main source of natural gas supply. This is not to say that there are no spot market trades in Asia, but that the majority of trade in this region is through contractual agreements. Contracts are essential for new LNG facilities to be built. Contract prices are often based on an oil-indexed formula to mitigate long-term pricing risk for buyers and sellers (Maxwell and Zhu, 2010).

Traditionally, contract prices are 'Ex-ship', reflecting downstream prices less gasification and other destination terminal costs and shipping, including insurance – thus, cost, insurance and freight (CIF) prices. Prices must therefore cover all costs associated with acquiring feedstock supplies, liquefaction and export terminal costs, plus a return on equity. Higher gas prices and falling value chain costs led to a surge of investment in global LNG liquefaction capacity and ships. In many cases, the risks associated with high capital costs of facilities are mitigated by long-term contracts where buyers guarantee minimum purchases, so that lenders are more willing to finance operations. Overall, lower capital costs reduce finance and capital costs and result in greater investment in LNG facilities and shipping costs, leading to greater LNG trade (Maxwell and Zhu, 2010).

Prices are often indexed and thus correlated with the Japanese Customs-cleared Crude (JCC) oil index or the Indonesian Crude Price (ICP) (DOE 2005). Because natural gas prices are indexed to oil in Asian markets, we observe higher prices. In North America, we see lower LNG prices because of lower natural gas prices, which are no longer tied to oil prices. This is an important consideration when looking forward to future LNG prices.

Figure 2 compares the natural gas prices in Alberta, the Henry Hub in the U.S., and LNG prices in Japan. The price differential between Asia Pacific and other markets has changed with the 2008 shale gas revolution. Although prices in Asia were not correlated with those in North America before 2008, there was no consistent differential compared to North American natural gas prices. As the availability of shale gas after 2008 greatly increased in North America, prices dropped while Asian prices were largely unaffected. After 2010, Asian prices began to increase due to demand growth. The divergence in the price of natural gas between North America and Asia after 2008 reflects this as illustrated in the graph by the consistently higher Japanese prices.

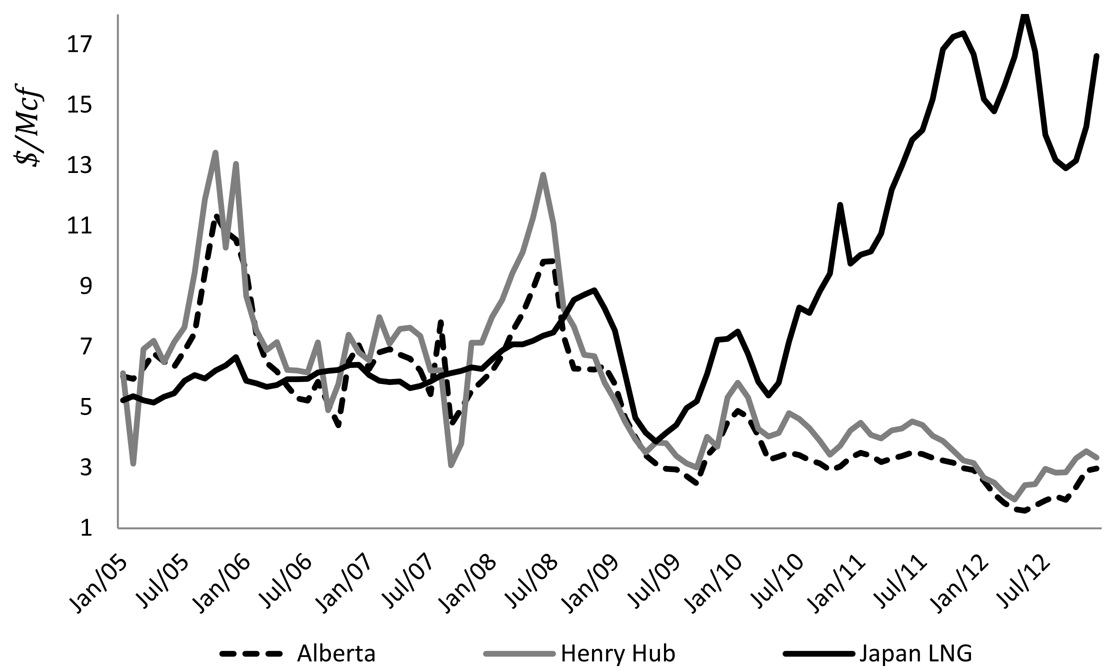

Figure 2: Historical North American Natural Gas Prices: 2005-2012 (IEA, 2012)

Though Asian LNG prices are currently very high, there remains the potential for a price collapse in the future, similar to what has occurred in North America after 2008. For example, there remains the possibility that Japanese researchers will find a way to exploit the vas gas potential of methyl hydrates (frozen methane) off the Japanese (and British Columbian) coast (BBC World News, 2013). While this may not have a major impact on LNG contracts because this is unlikely, a scenario is considered in this study where Asian prices collapse.

3. METHODS

As the aim of this study is to assess the economic viability of LNG facilities in British Columbia, I develop a simulation model to assess the benefits, costs and risks. The approach is to compile data on the costs of LNG production, consider potential prices, and model the conditions under which LNG production in British Columbia might be considered economical. Given that many of the costs are uncertain and may only be known within a range, it would be prudent to consider multiple possible cost scenarios.

One approach that is commonly used is to conduct sensitivity analysis by changing the values of uncertain parameters over a plausible range. We might calculate a base case by computing the best-guess of the values, then change the parameter values to their highest and lowest possible values. While this approach offers more information about the uncertainty of the costs of LNG production compared to a simple point estimate, it is limited by three major problems.

First, the sensitivity approach fails to take into account important available information regarding the assumed values of the parameters. For example, there may be different probabilities associated with the highest and lowest possible values, which is additional information that should be represented in the analysis. In many cases, the values near the best-guess are more probable than values near the extremes of the range.

A second issue with sensitivity analysis is that it does not provide information about the dispersion of the benefits. In the case of this study, the benefits are the profits from producing and shipping LNG from British Columbia to Asia. A policy maker, investor or firm may be interested in a project that has a smaller variance (risk) if all other factors are constant.

The third limitation of traditional sensitivity analysis is that it typically involves changing the value of a single parameter at a time, while in the real world multiple values may be subject to change (Jaffe and Stavins, 2007). Indeed, the values that the various parameters can take might be correlated. The assessment could be improved to simulate the real world if multiple scenarios could be considered where all variables are free to change concurrently.

As a result of these drawbacks to traditional sensitivity analysis, I have elected to use Monte Carlo analysis to model the uncertainty in LNG production costs. This type of simulation in which all values are allowed to change simultaneously is a more realistic means of modelling uncertainty in costs.

The first step is to develop probability distributions for the uncertain parameters in the cost model. If parameters are correlated, such correlation must be identified and integrated into the Monte Carlo simulation (Schade and Wiesenthal, 2010). This will avoid the creation of cases that are not realistic or possible. In the case of the LNG cost model in this paper, it is reasonable to assume that there are no correlations among the parameters – facility capital cost, shipping cost, operating cost, pipeline transportation cost, exploration and production, and emissions cost. The model run uses 10,000 iterations, following an analysis similar to that of Jaffe and Stavins (2007). As the National Energy Board considers granting 20-year export permits to companies looking to export LNG, a 20-year timeline will be considered for this model (National Energy Board, 2012).

The Monte Carlo analysis is based on the basic profit function:

$$(1) \qquad Net\ Profit = \sum_{i=1}^{20} \delta_i (P_i - C_i)\, Q_i,$$

where δ_i is the discount factor, Q_i is the quantity of natural gas that is liquefied, P_i is the end price for LNG and C_i is the cost of producing LNG per thousand cubic feet (mcf). The subscript, i, denotes the period in terms of years. The cost of LNG production is a function that can be factored into the various input costs:

$$(2) \qquad C_i = K + T_i + O + L_i + E_i + Em,$$

where K is the annualized cost of the LNG liquefaction facility, T_i is the shipping cost, O is the LNG facility operating cost, L_i is the pipeline transportation cost from the gas well to the LNG facility, E_i is the cost of exploration and production of the gas (wellhead price) and Em is the price of CO_2 emissions. The price of carbon emissions is treated as a cost in this function because the referent group is the LNG firm investing the in LNG facility. Thus, the profitability will be affected by the firm paying a price on emissions in the form of a carbon tax or a cap-and-trade system. Though a price on carbon may be of benefit to British Columbia as a whole through incentivising fuel switching to lower emission fuels, the carbon price reduces the margins on profitability for the LNG producer. The reason that the LNG producer bears this cost is that LNG from British Columbia will compete with other jurisdictions that do not put a price on carbon emissions. Note that in the function, the subscript is absent on the *K*, *O* and *Em* variables. This is because while these variables are drawn from their probability distributions in each run of the model, they are assumed not to change throughout the twenty year period of each iteration of the simulation. The reasons for this assumption are discussed in Section 3. All of the costs in Equation 2 are converted into dollars per mcf before being multiplied by the quantity (mcf) in Equation 1.

In the case of British Columbia, it is natural that the target markets for the province's LNG will be in the Asia Pacific Basin. This particular study focuses on the costs of producing and transporting LNG into these demand markets including Japan, South Korea, China, Taiwan and India. In particular, Japan is the focus, given its market share of the demand for LNG in the world and the availability of price data for this market. Figure 3 illustrates the structure of the Monte Carlo simulation.

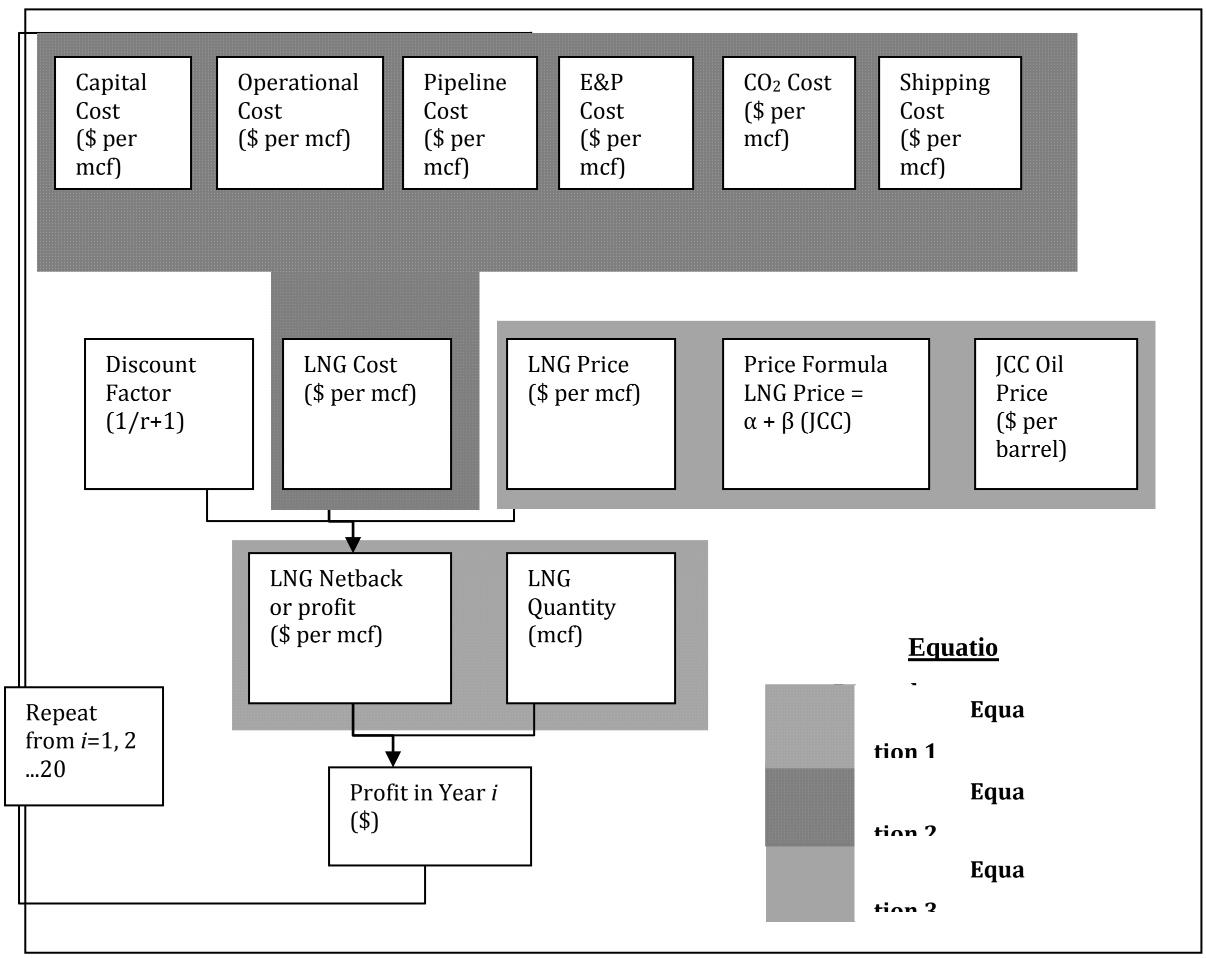

Figure 3: LNG Monte Carlo Simulation

Probability Distributions

The variables in Equations 1 and 2 are drawn from various probability distributions. The triangle, normal and step/uniform distributions are used for different purposes in the study.

The most common probability distribution used in this study is a triangular distribution. A key advantage of the triangular distribution is that a minimum and maximum can be set for each variable based on what an expert determines to be a likely lowest and highest outcome for each variable, respectively. A midpoint between the minimum and maximum is then the peak of the distribution. Given the limited information on some values for the model, this can ensure that the outcomes of the simulation come from a set of values likely to exist.

A normal distribution is used for the parameters in the LNG price Equation 3 (see Section 3: Prices). The formula has been derived from an OLS regression with the coefficients of this regression being the parameters of the linear formula. Thus, the estimated coefficients are estimated with a normal distribution and it is necessary to draw the parameters from the same probability distribution in the Monte Carlo simulation.

The other probability distribution used in the simulation is a step/uniform distribution. This is similar to a discrete uniform distribution, but instead of all values having equal probability, one particular range of values has a different probability from another range of possible values. For example, the values closest to the median may have a higher probability than the extreme values, but there is no reason to believe that a value slightly higher or lower than the median would have a different probability. This type of probability has been used for the oil prices, modelled after Jaffe and Stavins (2007).

Probability distributions for all variables used in the Monte Carlo simulation are displayed in Figure 4.

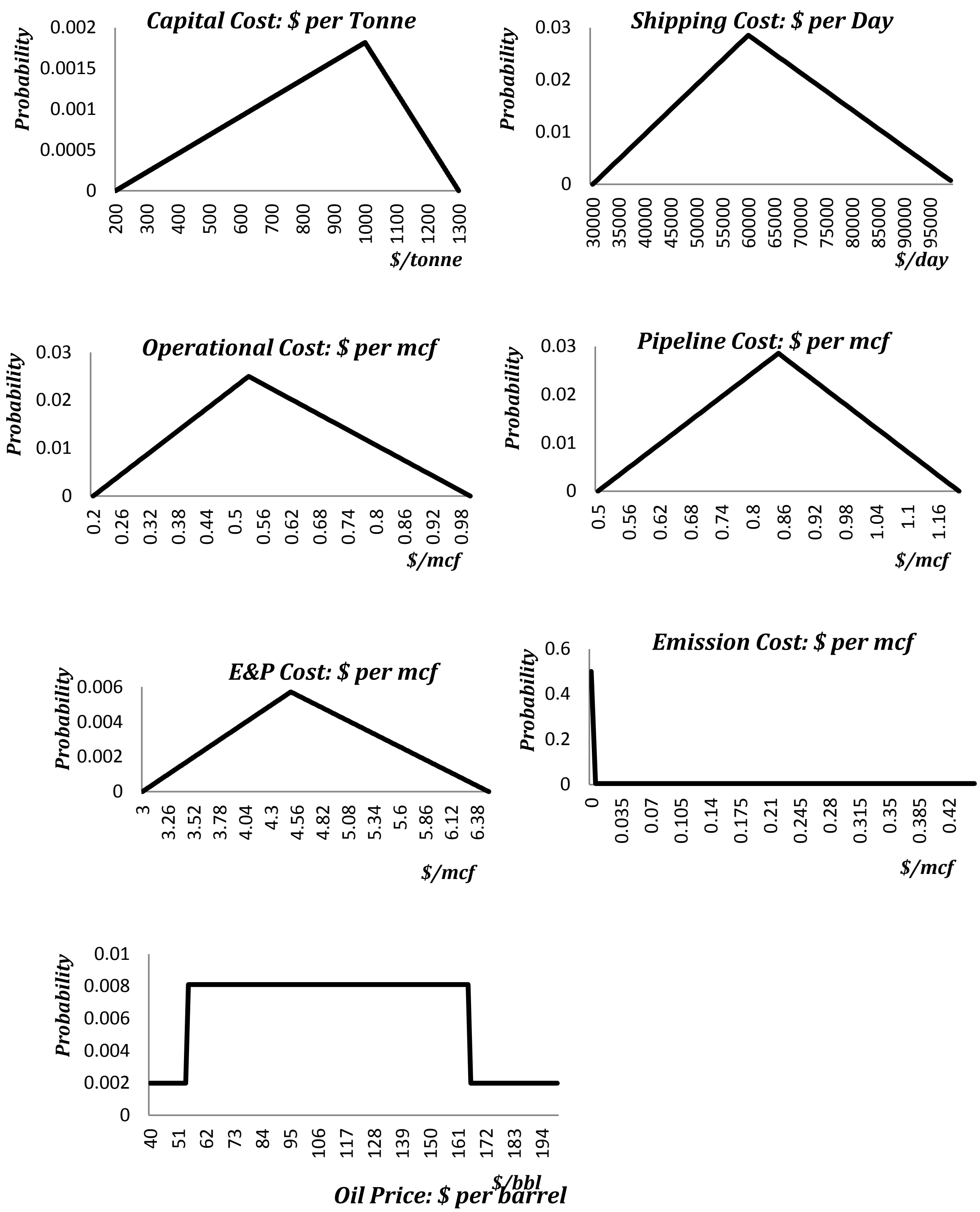

Figure 4: Probability Distributions for Simulation Variables

Price Disaster Scenario

A major concern for LNG facilities is the potential for Asian countries to develop their own shale resources and displace some of the demand for imported LNG. This may not be a major concern for potential LNG projects, as Japan and Korea do not have significant domestic resources. While China does have significant shale gas resources, the infrastructure in the country is not developed and demand growth is expected to outpace domestic supply growth (IEA, 2012). Additionally, there is potential for Japan to develop their domestic methyl hydrate resources if technologies advance and cost can be competitive with other sources of natural gas (BBC World News, 2013).

Though this is an unlikely scenario, it has been included as a risk in a Price Disaster Scenario simulation. In this run of the Monte Carlo model, there is a risk of price collapse for the LNG in order to compete with Asian domestic natural gas resources.

4. DATA

Next, data for the variables must be used to create probability distributions. The data assumptions used in this analysis are provided at the end of this section in Table 3. This section discusses the data used to construct the probability distributions of each variable.

LNG Costs

Investment in LNG projects requires very large capital expenditures, though recent technological improvements have reduced costs in all components of the LNG value chain. The costs in the value chain that are considered in Equation 2 include LNG facility capital costs, operating costs, shipping, pipeline transportation, exploration and production, and CO_2 emission prices.

Facility Capital Costs

The largest cost in the value chain is usually the liquefaction plant. The LNG industry uses cost per tonne of annual LNG production ($ per tonne) as a common metric for comparing the capital cost of liquefaction facilities. While $ per tonne is the unit used by the literature to discuss LNG capital costs, the cost per tonne must be converted into $ per mcf in order to be used in Equation 2. The cost can be approximated by multiplying tonnes by a factor of 46.729 in order to convert the figures into $ per mcf. The cost must be then converted into an annual cost that is to be amortized over the 20-year period.

Capital costs have fallen during the late-twentieth century, from $600 per tonne in the late 1980s to $200 per tonne by 2001. Approximately fifty percent of the capital costs are reserved for construction related costs, thirty percent for equipment, and the remainder for bulk materials (DOE, 2005). Discussions with Victor Ojeda of Shell International revealed that since the mid-late 2000s, capital costs are actually rising for LNG facilities. This is due to both the rise in commodity prices and the market power of contractors with the necessary expertise to build LNG projects. There is increasing competition for their time and with many projects being proposed, this has bid up the cost of constructing many projects (Ojeda, 2011). For example, one study found a j-curve of capital costs over the past decade in Australian LNG projects, with project costs ranging from $600-1300 per tonne (Beveridge, 2011).

A range of costs between $200-$1,300 per tonne is used in the simulation. The Kitimat LNG facility is estimated to cost $6.5 billion for the first phase with a capacity of 5 million tonnes per annual (mtpa), and $3.9 billion to increase the capacity by another 5 mtpa (National Energy Board, 2010). As it is the first major facility expected to be built in British Columbia, it is the basis of the study in terms of capacity and cost. I use $1,000 per tonne as the mode in the triangular distribution. In order to include the capital cost in Equation 2, the cost per tonne is converted into an annualized cost per mcf. Note that while capital costs can change between scenarios (each iteration of the model), the capital cost will not fluctuate over time. For this reason, capital cost is held constant over time, but allowed to fluctuate between iterations of the simulation.

Operating Costs

Another component of costs is the operational costs, about which there is limited information. One estimate puts the cost of operating a 1 mtpa LNG facility at $25.8 million per year: Staff of 60 ($4.8 million), property tax ($6.0 million), operation and maintenance ($3.0 million), electricity ($3.0 million) and insurance ($9.0 million) (Zeus Development Corporation, 2004).

The capacities of the LNG plants considered in British Columbia are much larger than the 1 mtpa plant discussed above. Unfortunately, accurate information about operational costs is not easily accessible. As the cost cannot be less than the 1mtpa plant, the $25.8 million per year operational costs will be the lower bound in the triangular distribution. At the upper bound, I multiply the operational costs of the 1 mtpa plant by ten to scale it up to a 10 mtpa plant in British Columbia. Due to the returns to scale expected with a larger LNG facility, it is not likely that the operation costs will be larger than $258 million per year. For similar reasons to the capital costs, operating costs can change between scenarios but will not fluctuate over time.

Shipping

According the DOE (2005), the cost of building LNG carriers has fallen from $280 million in 1995 to $150-160 million in 2005, which is still more than double the cost of a crude tanker (due to in cost of the insulated tanks). Larger ships enjoy economies of scale, and propulsion has become more efficient. In the long term, the capital cost of ships appears to decline (DOE, 2005). However, construction of LNG carriers is not counted as a direct component of the development of an LNG export facility; rather it is assumed that ships will be chartered. Platts tracks the daily costs of LNG carrier charters, reporting a sharp increase in charter costs in 2011 from $40,000 per day to over $90,000 per day. The sharp increase in price can be attributed to Japan's increased demand for LNG following the March 2011 earthquake, but this is not expected to be sustained in the long term as new carriers are built (Platts LNG Daily, 2011-2012).

As the observed daily charter rates for LNG carriers have resided within a range between $30,000 per day and $100,000 per day, a triangle distribution for daily charter rates is used with these values as the minimum and maximum, respectively (Platts LNG Daily, 2011-2012). A mode of $60,000 per day is expected to be in line with the long-term charter rate, and roughly equivalent to the 15-year amortized costs of purchasing an LNG carrier.

Pipeline Transportation

The CGPR (2010) provides estimates of transportation costs through existing natural gas pipelines in Canada. According to the report, the average transportation costs from northern to southern British Columbia are $0.85 per mcf, a distance of approximately 1000 kilometres (CPGR 2010). This conservative estimate is used with a range (+/- $0.35) to consider the possible changes in tolls and tariffs on pipelines. Again, a triangular distribution is used to represent a declining probability that the pipeline transportation cost is further from the mode of

$0.85 per mcf of natural gas.

Exploration and Production

Estimates for exploration and production costs are from a shale report estimating exploration and production economics (Medlock et al., 2011). These costs include exploration and production, operating costs, royalties and production taxes, return on investment, and processing. More recently, there has been some discussion of steeper production declines coming from shale gas wells, resulting in higher exploration and production costs (Swindell, 2012; Hughes, 2013). This scenario may present an angle that has not been considered by stakeholders in the public LNG discussions and the additional costs and impacts on LNG economics are considered in the model.

Based on the costs discussed above, a minimum cost of $3.00 per mcf and a maximum cost of $6.50 per mcf is established as a range that reflects the costs of natural gas exploration and production in British Columbia. A mode of $4.50 per mcf has been chosen to reflect the long-term costs associated with hydraulic fracturing and their steep decline curves.

Emission Cost

A tax on carbon emissions needs to be considered in the analysis. Currently, British Columbia only taxes combustion emissions, not process emissions. This means that natural gas is only taxed if it is used as fuel for electrical generation, transportation or other end uses. As LNG will be shipped outside the jurisdiction for end-use, the carbon taxes on emissions are not clear. The current carbon tax in British Columbia on combustion is $30 per tonne of CO_2e (Province of British Columbia, 2013). As noted in Section 2, there is no subscript for time period specified in Equation 2. The assumption for the model is that while the carbon price may vary from scenario-to-scenario, it would be unlikely to fluctuate dramatically from year-to-year. Therefore, the carbon price has been allowed to vary between iterations but to be constant for each iteration.

A step/uniform distribution is used to simulate potential carbon prices in the future for British Columbia. In half the scenarios, no carbon tax is levied on LNG production. In the other scenarios, a carbon tax between $0 and $90 per tonne is levied on natural gas production destined for LNG exports. There is a uniform distribution of probabilities on each of the values, if a carbon tax is levied. See Figure 4 for a graphical representation of the probability distribution for emission cost.

Receiving terminals

In the analysis, we can ignore the regasification facility cost, because prices for LNG do not include regasification in the price (IEA, 2012). Though some shipments of LNG from British Columbia will be sold free-on-board (FOB) at the terminal arm in British Columbia, others may be sold Ex-ship at the destination. It is assumed that FOB prices are equal to Ex-ship prices, subtracting costs associated with shipping. The reason for this assumption is that we have access to price data from Japanese LNG imports and, more importantly, the assumption simplifies the study considerably without sacrificing realism.

Facility Capacities

The Kitimat LNG facility was the first LNG facility in British Columbia to receive regulatory approval (NEB, 2010). The facility will have a capacity of 10 mtpa of LNG after two phases of the project are completed. A proposed BG Group facility in Prince Rupert is also slated to have a 10-mtpa capacity. Two other proposed projects are expected to have similar capacities: Petronas and Shell's first phase of Canada LNG (NEB, 2012).

For the purpose of this simulation, a generic facility with a capacity of 10 mtpa is considered, which is equal to 467,289,720 mcf per year. Note that though there is a subscript on C_i, it is assumed that the quantity of LNG produced is the same in each year. For a more detailed description of proposed LNG projects see Appendix 1.

Prices

In long-term contracts, common in the Asia Pacific markets, pricing for LNG in Asia is determined by a standard formula:

$$P_i = \alpha + \beta(JCC), \tag{3}$$

where α and β are parameters that are stated in a contract, and JCC is the Japanese Crude Cocktail price (DOE, 2005). As the JCC price tracks international oil prices, such as the Brent

Crude price, Equation 3 illustrates that LNG prices in Asia are correlated with oil prices rather than natural gas prices. This is a key difference between North American and Asian natural gas markets. I assume that the Asian LNG prices continue to be indexed to the JCC in the future and that JCC will continue to follow Brent crude oil prices.

Though contract terms vary, the average LNG pricing formula can be used as an estimate of LNG prices in Asia, given the price of crude oil. LNG prices are given an upper and lower bound by constraining the range that oil prices are allowed to fluctuate. As oil prices are difficult to forecast and can be very volatile, it is hard to determine probabilities for a particular oil price. Thus, I have taken a range of 'likely' oil prices and a broader range of 'extreme' oil prices to be the possible oil price values. The more likely oil prices have been assigned a higher probability of occurrence than the more extreme values, though all values within each category are assigned the same probability of occurrence. The LNG price is then a random draw from the distribution, inserted into the pricing formula.

To determine the LNG price formula, I use monthly average LNG import price data from the IEA (2012) to estimate the formula by a regression of LNG prices on oil prices. The resulting constant term and the coefficient for oil price from this regression are the estimated parameters (α and β, respectively) of Equation 3. Together with the error term, ε, that has a mean of zero, the equation will be used included in the Monte Carlo simulation with oil prices drawn from the above distribution provide LNG prices. The parameters – α, β and ε – are assumed to be normally distributed with a standard deviation as stated in the regression results of Section 4.

Oil prices are drawn from a step/uniform distribution similar to Jaffe and Stavins (2007). Prices are drawn from a uniform distribution between \$55 and \$165 per barrel, and with a lower probability from a uniform distribution between \$40 and \$200 per barrel. This is consistent with the range considered in Schade and Wiesenthal (2010).

Summary

A summary of the key parameters in the Monte Carlo simulation is provided in Table 3. Note that all dollar amounts are discounted to present value using a discount rate of 4.5 percent as the standard public sector discount rate. The next section uses the data discussed in this section to run possible scenarios for the study.

Table 3: Summary of Assumptions for Variables and Parameters

Parameter (/mcf unless stated)	Mode (if applicable)	Min-Max range or standard deviation	Probability Distribution Function	Source(s)
Oil price (/bbl)	$110	$55-165 ($40-200 with lower probability)	Uniform/Step	Jaffe and Stavins, 2007
Carbon Price (/tonne)		$0-90	Uniform/Step	Province of British Columbia, 2012
Capital Cost (/tonne)	$1,000/tonne	$200-1,300/tonne	Triangle	DOE 2005; NEB, 2011-2013
Pipeline	$0.85	$0.50-1.20	Triangle	CGPR, 2010
Exploration and Production	$4.50	$3.00-6.50	Triangle	Medlock et al., 2011
LNG Operating Costs	$0.53	$0.20-1.00	Triangle	Zeus Development Corporation, 2004
Shipping Costs (/day)	$60,000/day	$30,000-100,000/day	Triangle	Platts LNG Daily, 2010-2012

5. RESULTS

The approach used here employs two steps: A simple regression to derive an estimate of the LNG pricing formula and then the use of data to find the oil price that makes LNG shipments economical viable from British Columbia.

Price Regression

The oil and LNG price data used for the price regression comes from the IEA (2012). When the LNG price is regressed on JCC crude oil prices, the results estimate a price formula as follows:

$$P_i = 0.827 + 0.117(JCC_i) + \hat{\varepsilon}_i \,,$$

where $\hat{\varepsilon}_i$ is the residual. The ε coefficient on JCC is significant at the 1% level and the constant is significant at the 10% level. A standard error of 0.981 has been estimated for the regression and is used as the standard deviation for the error in the Monte Carlo simulation. Summary statistics from the price regression are listed in Table 4.

Table 4: LNG Price Regression Summary Statistics

Variable	Coefficients	Standard Error	t Stat	P-value
constant	0.826**	0.470	1.757	0.084
JCC Price	0.117*	0.006	18.675	0.000
R^2		0.839		
Standard Error		0.963		

* Coefficient is significant at the 1% level
** Significant at the 10% level

As shown in Figure 5, the predicted price follows the observed average monthly price quite closely.

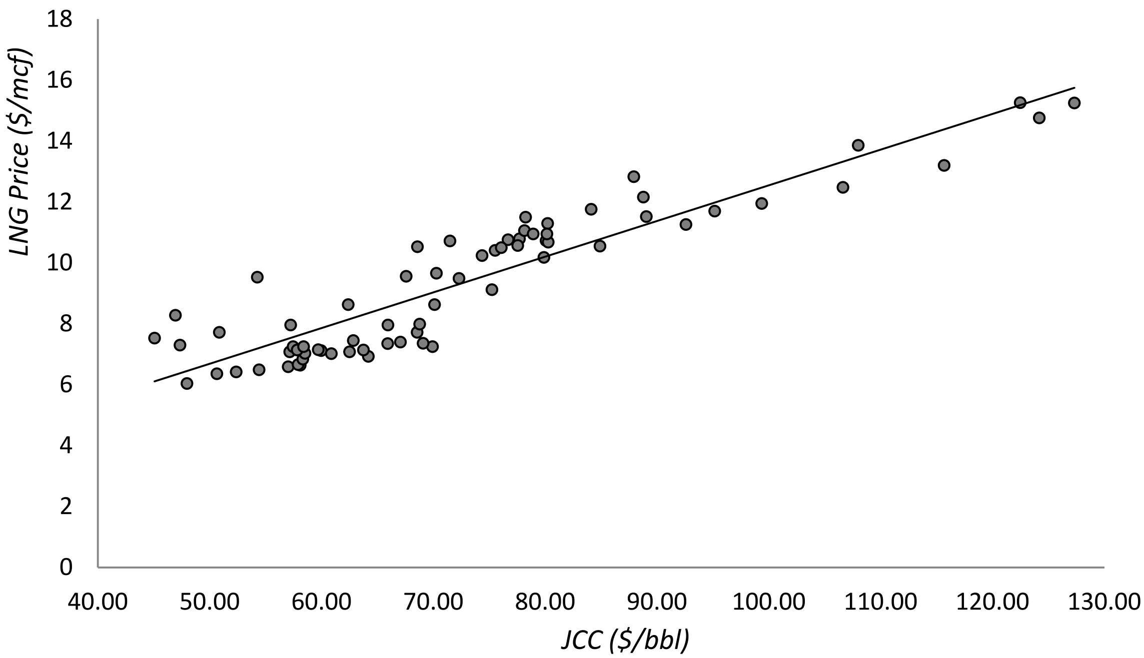

Figure 5: A Simple Regression of LNG prices on oil prices.

Monte Carlo Simulation

The Monte Carlo simulation was run with 10,000 iterations and the resulting data is considered before the final results are presented. Averages of this data are displayed as the total additional average cost of LNG to natural gas production is summarized in Table 5. These costs assume a 95% capacity factor in both the LNG plant and any additional pipeline that is required to transport gas from existing infrastructure to the coastal LNG facility. As the opportunity cost for downtime is significant for LNG facilities, they are operating at all times possible and it is reasonable to assume that the capacity factor would be very high.

Table 5: Significant costs in the Value Chain

Variable	Average Value ($/mcf)
LNG Capital Cost	$1.49
Average Shipping cost (Japan)	$0.61
Plant Operating costs	$0.58
Pipeline to LNG Plant	$0.82
Exploration and Production	$4.67
CO_2 Emissions	$0.12
Total Average Cost	**$8.29**

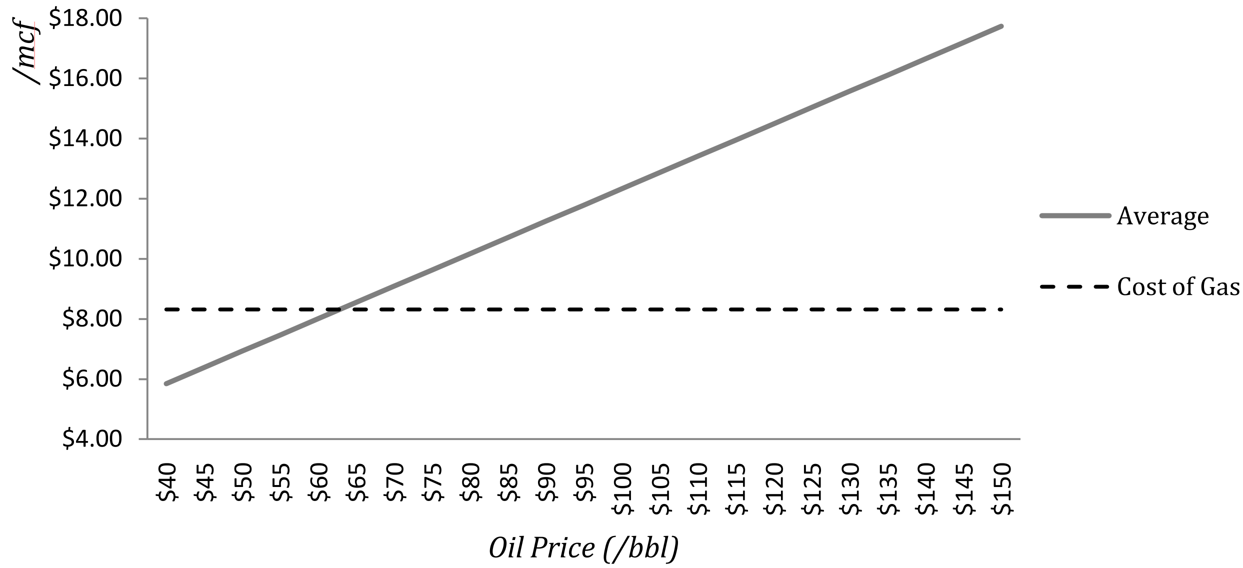

Figure 6: Breakeven-Price Point Estimate

The analysis of LNG production costs yields an average additional cost of $3.50 per mcf above the British Columbian cost of supply. This means that, to make an LNG project economically feasible, the final LNG price premium between Asia and North America must be $6.50 per mcf. This yields an average price of $8.29 per mcf to make an LNG project in British Columbia feasible for a company to invest.

Figure 6 displays the Japanese LNG prices for which it would be economical to ship LNG from British Columbia to Japan. The cost of extraction and production, liquefaction, shipping and regasification is estimated to be $8.29 per mcf. This translates to approximately $64 per barrel of oil, depending on the pricing formula. If oil is expected to stay above this price on average for the life of the terminal, then it is economical to ship LNG to Japan.

Futures prices could give an indication of what markets expect a future price to be based on current information. Though there are no LNG futures markets in the Asia Pacific regions, futures markets exist for crude oil. Figure 7 illustrates what the LNG price would be if Equation 3 is applied to the futures price for crude oil. The LNG price per mcf is Equation 3 with a light crude oil futures price substituted for JCC. In this case, the price of LNG in Japan could fall nearly one dollar between now and 2019. The futures prices are for light crude oil similar to Brent, as report by the CME Group (2013).

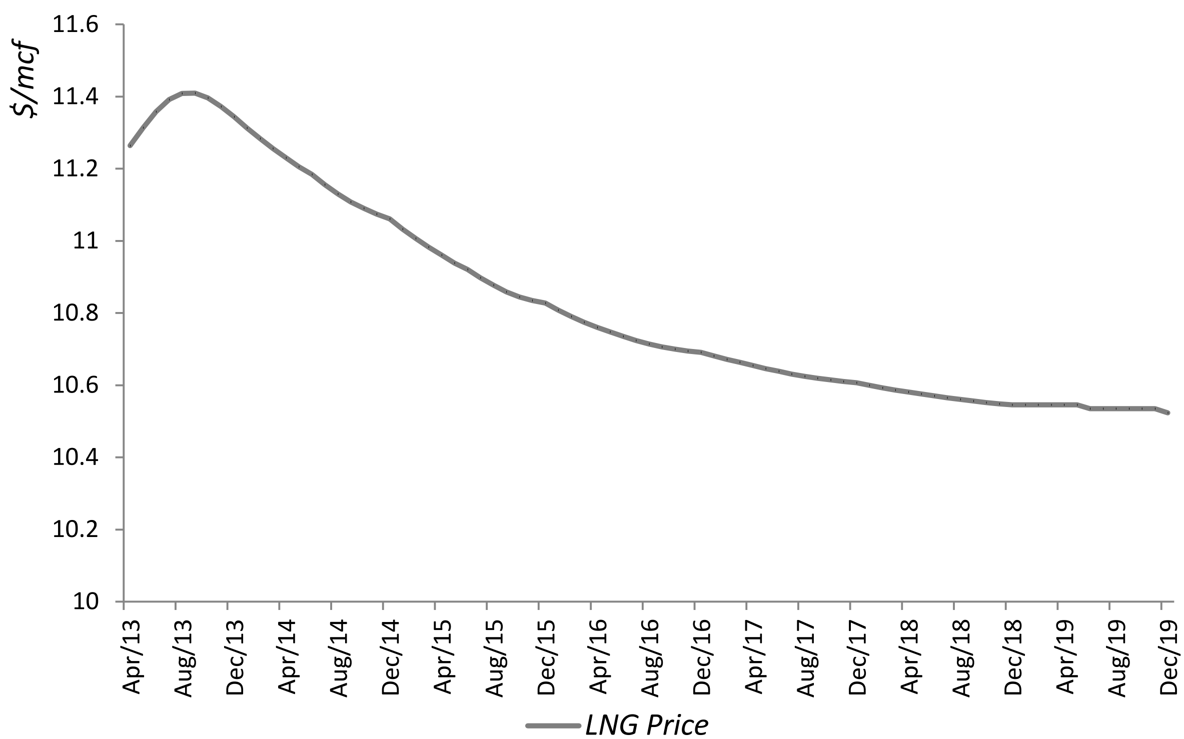

Figure 7: LNG Futures Price Using Formula and Oil Futures

If the futures market is any indication of future crude oil prices, this would mean that the future LNG price is expected to be sufficient to economically ship LNG from BC to Japan between 2013 and 2019, assuming that the LNG were to cost an average of $8.29 per mcf to produce and ship. Though the timelines of the LNG projects exceed the futures curve, it is an indication that the project could be economic in the early years of operation. However, this does not take into account future shocks to the market such as new technologies, geo-political events, and so on. Geo-political events, such as wars or supply disruptions from the Middle East (ex. the oil embargo of 1973), have historically resulted oil prices spikes, but are difficult to predict (DOE, 2005).

Monte Carlo Results

The results from the Monte Carlo simulation are the various scenarios of forecasted profits from an LNG facility in British Columbia. The profitability of each scenario is the result of one iteration of the model; a summation of the discounted costs and prices over the 20-year period. Data from the 10,000 iterations are complied and displayed as a distribution in the form of a histogram in Figure 8.

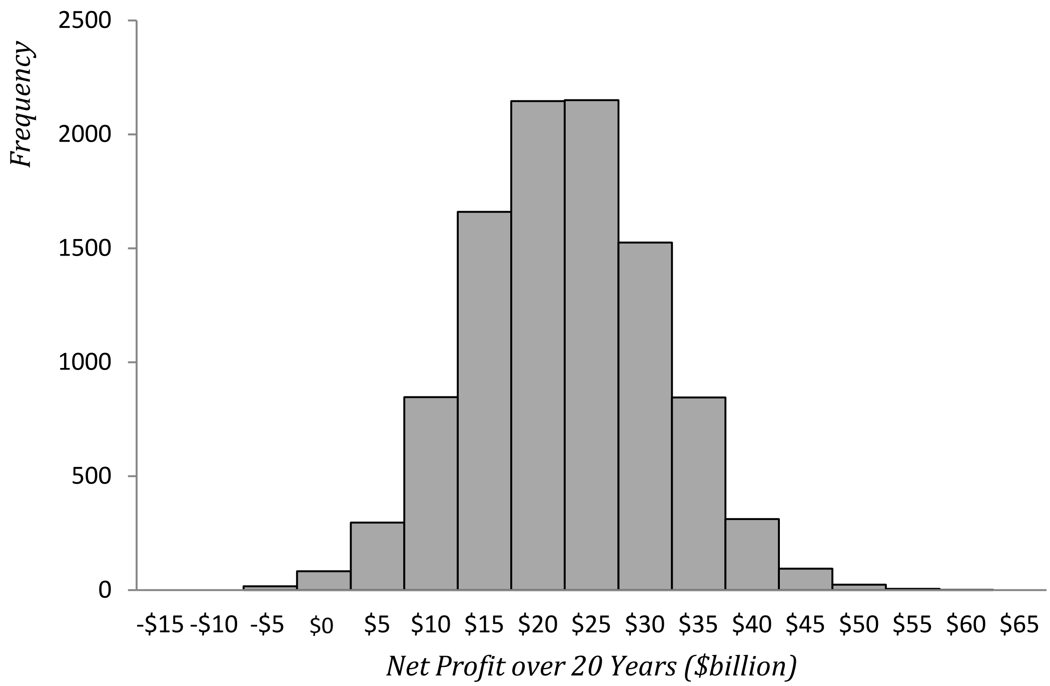

Figure 8: Histogram of Monte Carlo results

In only 0.07% of the scenarios does the LNG facility lose money over the 20-year period. By far the largest influencing factor in determining the economic return on LNG exports is the sale price in Asia, which is ultimately determined by the price of oil. In our point estimate, we determined that the price of oil should be at least $64 per barrel to break even.

Price Disaster Scenario

Another 10,000 iterations of the model was run, but with a possibility of a price collapse in Asian LNG markets. An event where Asian supply increases significantly, or demand decreases significantly, is unlikely due to reasons discussed in Section 3. However, the Price Disaster scenario is also considered in which there is a fifty percent chance that the price of LNG in Asia is reduced by half due to an increase in domestic gas supply. A histogram that displays the net profit over 20 years in each of the iterations of the Monte Carlo simulation is displayed in Figure 9.

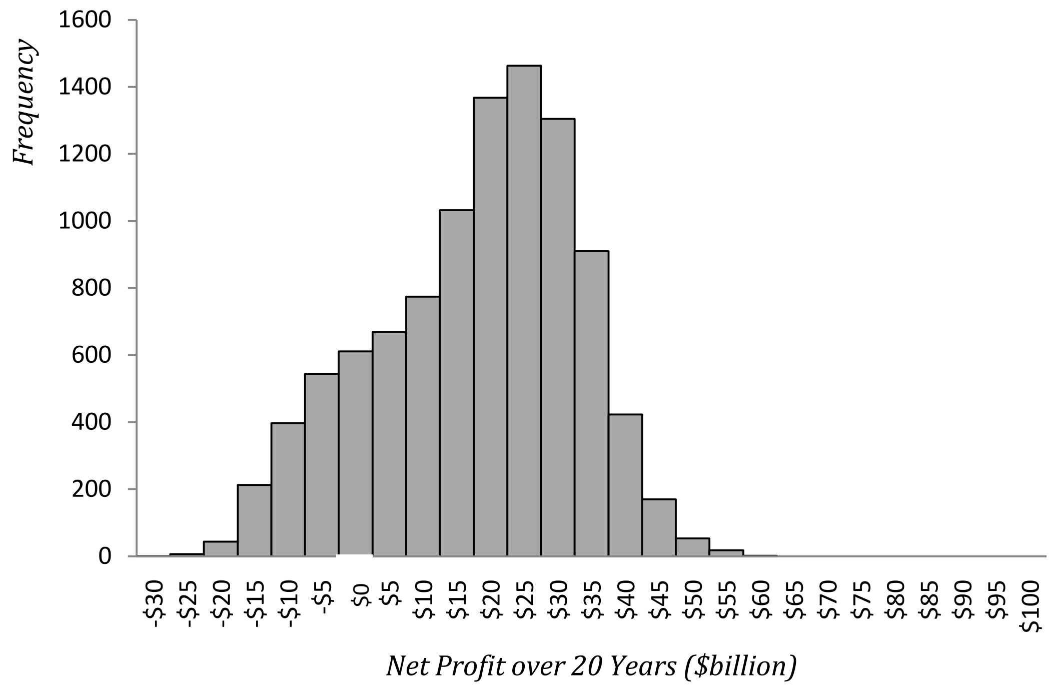

Figure 9: Histogram of Price Disaster Scenario results

Compared to Figure 8, the Price Disaster scenario results indicate that there is significantly more risk of negative net profit. In approximately 18.4 percent of the cases, the profit from the LNG facility was negative over the 20-year period. While the Price Disaster scenario is not likely to occur, it illustrates the importance of the high Asian prices to the success of LNG projects in British Columbia. If prices fall significantly, there is a risk that LNG projects will not be economically viable.

6. CONCLUSIONS

Given the changes in the natural gas industry in North America, this study set out to assess the economic viability of an LNG industry in British Columbia using a Monte Carlo simulation. The uncertainties in costs and prices were modelled and given the results of the simulation, it would appear that there is great potential for the LNG industry in British Columbia. In 99.9 percent of the scenarios run, there was a net profit generated by the LNG facility. However, when the Price Disaster scenario was modelled as a price collapse in Asia, there were significantly more cases where the LNG facility generated a net loss. This suggests that the largest risk for the LNG facilities being proposed in British Columbia is the price risk.

Fortunately, there is a mechanism for mitigating the price risk for LNG projects. Most LNG sold in the world is through long-term purchase agreements that specify a pricing formula. As long as the price of oil is above an average of approximately $64 per barrel, there is potential for a profitable LNG facility. Additionally, contracts specify pricing floors and ceilings to protect both the buyers and sellers from price shocks. As the details of private contracts are confidential, the author was not privy to the details of agreements. However, if the terms of a purchase agreement are satisfactory, it is likely that an LNG proponent can significantly reduce the risk to their project.

As the largest risk for LNG projects is the price risk, there are opportunities for future research to analyze the oil price as the determinant of LNG prices. Though forecasting is a challenging task, it may be useful for LNG proponents to understand the risks and uncertainties for oil prices in the future. This is especially pertinent given the increases in shale and tight oil production in North America, leading one to question the potential for an oil market shock, similar to the natural gas markets in 2008. However, regardless of any analysis undertaken, the risk and uncertainties of LNG development in British Columbia remain a question that can only be answered over time.

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