Executive Summary

The Kitimat Liquid Natural Gas project (KMLNG) represents a substantial opportunity for several major players in the BC Natural gas sector and many are excited at the possibilities of the proposed KMLNG and possible economic activity to follow. Recently the companies Apache, EnCana, and EOG resources cleared final government environmental approval to move to the final stage of application to make the KMLNG a reality. The KMLNG will include the construction of a 463 km pipeline project between Summit Lake BC and Kitimat as well involve the construction of the LNG plant itself. The natural gas resource that these companies are extracting comes with many consequences both positive and of management concern for the province.

Considerations regarding green-house gas emissions, ecological impacts, water consumption from hydraulic fracturing, and long-term site degradation are all considerations that are not accounted for in financial calculations for the KMLNG. This project will examine the Net Present Value of KMLNG from the social perspective for British Columbia and compare this to the value expected for the companies Apache, EnCana and EOG resources on a go forward basis. This project will examine both the financial aspects of KMLNG for industry and contrast this with the value of KMLNG from the social perspective. This project will contrast the positive economic benefits with the cost of the ongoing gas industry developments in British Columbia. The problem with the current economic condition is that the price of natural gas is low due to excess supply in North America. With Canada’s first LNG export project completed, access to energy-hungry Asian markets could change the economic equation dramatically.
# Table of Contents

Executive Summary ................................................................. iii

Table of Contents ...................................................................... iii

Dedication ................................................................................ vi

Chapter 1

Introduction .............................................................................. 1

Research Problem ..................................................................... 4

Chapter 2

Nature of the Natural Gas Industry in BC

2.1 Unconventional Gas Economics .............................................. 7
2.2 Kitimat Facility ...................................................................... 9
2.3 Pacific Trails Pipeline .......................................................... 12
2.4 Canadian Natural Gas Supply ................................................ 13
2.5 North American Energy Demand ......................................... 14
2.6 World LNG Market ............................................................ 21

Chapter 3

Financial Viability of the KMLNG Project and Pacific Trails Pipeline

3.0 Methodology ........................................................................ 25
3.1 Base Case LNG deals .......................................................... 28
3.2 NPV for Project- Industry Based .......................................... 30
3.3 NPV Calculations Base Case Scenario .................................. 33
3.4 NPV Calculations Reduced Rates ......................................... 36
3.5 NPV Calculations – Cost Over-runs, Production Delays and Increased Fixed Costs ........................................... 37

Chapter 4

Social and Environmental Impacts

4.1 Social Impacts of Kitimat LNG ............................................. 40
4.2 Cost-Benefit for Kitimat LNG .............................................. 41
Chapter 5

BC Royalties and Potential Changes

5.1 Current Royalty Rates and Programs ............................................ .43
5.2 Future Royalty Rates and Options ............................................ .45

Chapter 6

Financial Analysis

6.1 Market Demand for LNG .......................................................... .46
6.2 Social Cost Associated with KMLNG ......................................... .47
6.3 Capital Asset Pricing Model to Assess KMLNG ............................ .49

Chapter 7

Social Cost-Benefit Analysis for KMLNG

7.1 Using Cost-Benefit Analysis for KMLNG .................................... .51
7.2 Cost-Benefit Analysis ............................................................... .54
7.2.1 Specification of Alternative Projects ........................................ .54
7.2.2 Decision on Benefits and Costs with Standing ....................... .55
7.2.3 Impact Categories and Measurement Indicators ...................... .57
7.2.4 Quantitative Impacts for KMLNG .......................................... .69
7.2.5 Discounted benefits of KMLNG ............................................. .71
7.2.6 Social NPV of KMLNG ....................................................... .72
7.2.7 Quantitative Impacts for KMLNG .......................................... .74
7.2.8 CBA Recommendation ...................................................... .76

Chapter 8

Conclusions and Recommendations ............................................... .78

Appendices

Appendix 1 – Conversions for KMLNG Production Volumes ............ .82
Appendix 2 – Conversions for KMLNG Production Volumes ............ .82
Appendix 3 – Conversions for KMLNG Production Volumes ............ .83

Bibliography .................................................................................... .75

List of Tables ................................................................................... .89

List of Figures .................................................................................. .90
To my loving wife Vanessa and four wonderful children: Devin, Logan, Amy,

and Gavin; this was for you foremost, and I love you all.
Chapter 1

INTRODUCTION

The oil and gas sector is one the fastest growing segments in the Canadian economy and in British Columbia this industry has continued to grow in importance. This sector is an important source of employment, income and revenue for the government (in terms of royalty and tax revenues). The revenue from oil and gas industry in BC for 2010 is estimated at C$1.7 billion (BC Government, 2011). This amount includes fees, levies, and royalties collected for oil and gas for the fiscal year end 2010. The entire oil and gas industry in Canada is estimated to directly and indirectly employ more than half a million people (TQM Consulting, 2010).

While oil has had substantial increase in demand and consequent price increases, the natural gas industry has witnessed an oversupply situation and subdued price conditions. Recent technological advancements in unconventional drilling\(^1\) and subsequent increased production of natural gas has created excess supply situation in BC and North America. The United States currently is the traditional market for natural gas from BC and they are also experiencing an oversupply situation. The result is that natural gas producers in Canada have to look to other markets such as in Asia where demand is growing for natural gas in the form of LNG. Moreover, this strategy will enable Canadian natural gas producers to reduce their dependence on US markets and de-couple from US markets.

\(^1\) Unconventional drilling of natural gas involves horizontal drilling and fracturing techniques to develop larger volumes of natural gas in one well versus previous conventional techniques that entered formations vertically and did not involve as sophisticated fracturing techniques.
In October 2011, the National Energy Board\(^2\) (NEB) of Canada approved an application by *KMLNG Operating General Partnership (the company)* for a license to export LNG from Bish Cove, located near Kitimat, BC for a period of 20 years. As a result, the company was permitted to export a total of 200 million tonnes of LNG over 20 years once production at the facility commences. Construction of the Kitimat LNG facility is planned to begin in 2012, with commercial operations expected to commence in late 2015 (KLOGP, 2011).

The Kitimat Liquid Natural Gas project (KMLNG) represents a substantial opportunity for several major players in the BC Natural gas sector and the industry is excited at the possibilities of the proposed KMLNG and possible economic activity to follow. The Kitimat LNG Terminal is a proposed project of Kitimat LNG Inc., a Calgary-based private company focused on the development of liquefied natural gas (LNG) and related facilities in North America (Apache Corporation, 2011). Kitimat LNG is 40 per cent owned by its managing partner Apache Canada Ltd.\(^3\), 30 per cent owned by EOG Resources Canada Inc., and 30 per cent owned by EnCana Corporation (KLOGP, 2012). Apache has agreed to acquire 51 percent of Kitimat LNG Inc.'s planned liquefied natural gas (LNG) export terminal in British Columbia (Apache Corporation, 2011). Recently the companies Apache, EnCana, and EOG resources cleared final government environmental approval to move to the final stage of application to make the KMLNG a reality. The KMLNG will include the construction of a 463 km pipeline project between Summit Lake BC and Kitimat as well as the construction of the LNG plant itself.

\(^2\) The National Energy Board is the federal body that functions to regulate pipelines and energy development and trade in the Canadian public interest.

\(^3\) Apache Canada Ltd. is a subsidiary of Apache Corporation based in Houston, Texas.
Considerations around long-term site degradation, green-house gas emissions and water consumption from hydraulic fracturing are all considerations that are not accounted for in financial calculations for the KMLNG and will be discussed later in this paper. This project will examine the Net Present Value of KMLNG from the social perspective for British Columbia and compare this to the value expected for the companies Apache, EnCana and EOG resources on an ongoing basis. This project will examine both the financial aspects of KMLNG for industry and contrast this with the value of KMLNG from the social perspective. This project will consider the benefits to industry for undertaking the project and will contrast the positive economic benefits with the cost of the ongoing gas industry developments in British Columbia.

The reason for the move to Kitimat and markets to Asia and beyond stems from the current disparity between the well-established North American market and the natural gas value globally. The problem with the current economic condition is that the price of natural gas is very low due to excess supply in North America with natural gas reserves at an all-time high. With Canada’s first LNG export project completed, access to energy-hungry Asian markets could change the economic equation dramatically for the entire North American natural gas industry. KMLNG was initially proposed as an import terminal and has gone through many different stages of regulatory approval and ownership since first being proposed. The estimate for the cost of the terminal is around $3.0 Billion USD and will also require the completion of the 36” Pacific Trails Pipeline project which has a capital cost value of $1.2 Billion USD (Pardy, 2010). The proposed facility in Kitimat is expected to have an initial capacity of 5mmtpa (6.9bcm or 700mmcf / day) and is expected to be completed in the spring of 2015 (KMLNG,
The plant will be supplied by Apache, EOG and EnCana’s existing gas fields in Northeast BC, where estimates claim over 1.5 TCM of marketable gas resources exist (GOC, 2011). These recoverable natural gas reserves in BC could allow for several other LNG plants in Kitimat as well as future expansion of the current planned facility (KLNGOP, 2012).

The Research Problem

Motivation for the move to Kitimat lies with the current and future economic demand for natural gas in North America as compared to Asia (GOC, 2011). Figure 1 shows the current and historic value of North American Natural Gas at the NYSE based on Henry Hub price indexing.

Figure 1: US price expectation with predictions Source: USEIA, 2012 and BP, 2011

What is evident in this graph is that North American demand has softened due to technological change in directional drilling and hydraulic fracturing techniques resulting in a glut of North American gas. Another concern with this forecast is the future cost / MMCF of natural gas over the next few years. New drilling and well stimulation
practices related to unconventional drilling make available volumes of gas much higher and more viable to develop. The result is that previously unrecoverable or cost-prohibitive to large scale gas developments are now being pursued across North America (OGC, 2011). In Asia, countries such as China, Korea, and Japan are looking for energy alternatives to highly pollution options such as coal and potentially dangerous nuclear power. With Kitimat is completed, this plant would be the closest foreign LNG terminal to these markets and would offer these countries access to LNG from North America. The current value and proposed future values for natural gas in Asia are approximately $12.00 US / MCF as compared to the current value of $2.42 US / (2012-02-15) MCF for North American gas (Pardy, 2010). The motivation to secure long-term supply agreements with Asian buyers for over four times the current value is the driving factor for Kitimat and supports the capital budgeting decision. At the same, the project has evoked strong criticism from many rural communities especially from First Nations on the ground of increased risk to their communities and possible social impacts on the rural habitats. Some of the critics argue that the proposed Kitimat LNG puts all the costs (economic and social costs) on to the communities and the firms are able to maximize all the potential gains from the project. In view of the controversy, the present study examines the financial and social implications of the Kitimat pipeline project. The study focuses on the following:

1. What would the profitability be for the BC Natural Gas industry after the completion of the Kitimat LNG facility before and after discounting the effects to the environment?
2. What is the cost-benefit from a social perspective should the KMLNG and PTP projects move forward?

3. Given a new market, are the current royalty rates reflective of the *global value* of natural gas?

The study is organized as follows: Chapter 2 will review relevant literature pertinent to the potential LNG project and the natural gas industry for BC. Chapter 3 will discuss the financial viability of the KLNG project as well as the Pacific Trails Pipeline (PTP). Chapter 4 will discuss the social and environmental impacts that could be a potential result of the project should the decision to move forward be made. Chapter 5 will discuss the current royalty programs in British Columbia and investigate the potential for changes with the current royalty system given the economic potential for Kitimat LNG in BC. Chapter 6 will investigate the financial analysis of the KMLNG project give the parameters in the project review and chapter 7 will look at the KMLNG project using the Cost Benefit Analysis approach.
Chapter 2

NATURE OF THE NATURAL GAS INDUSTRY IN B.C.

2.1 Unconventional Gas Economics

Commercial Development of shale gas resources is a decision that is made after much analysis, data collection and planning (CSUG, 2011). The stages of development involve many processes that have to be undertaken in order to proceed with an oil and gas development. The economic assessment of different stages from a financial perspective is difficult on a unit-of-gas produced basis as the production varies for different areas and for different producers; however, production costs can be averaged based on an average efficient operator (Healing, 2010). Healing (2010) interviewed oil and gas professionals regarding the break-even cost for Natural gas developments in British Columbia. It was discussed that emerging technologies in hydraulic fracturing and completions technology, coupled with royalty incentives, larger well sizes, and improved drilling techniques, make plays in the Horn River and Montney basins profitable at a Henry hub gas price of approximately $4.00 / MCF to the current US market. This figure is considered the break-even point for this analysis as contemplating different efficiencies for different operators would require access to confidential company information. This $4.00 / MCF figure includes the cost of all production including exploration, drilling, royalties, and production costs that currently bring marketable gas to the marketplace US consumer. It involves the cost of piping the natural gas to the average US distribution center as well as the cost of refining the natural gas to its raw state which is required before transport to Kitimat for liquefaction.
is possible. Below is the breakeven cost of production for producers of natural gas in Northeast BC.

Table 1: indicating natural gas market break-even points Schaefer (2009).

<table>
<thead>
<tr>
<th>Breakeven Cost Structure for Natural Gas Production in North East BC</th>
</tr>
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<tbody>
<tr>
<td>Operator Type</td>
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<tr>
<td>----------------</td>
</tr>
<tr>
<td>Efficient</td>
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<td>Average 2013 Operator</td>
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<tr>
<td>Low Efficient</td>
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</table>

As shown, operators in Northeast BC operate on a breakeven cost of around $4.00 MCF according to EnCana in 2010. In the Ross summary, EnCana explains that their total supply cost for the area known as Cutbank Ridge is $3.15 MCF (2011). This information was discussed with CEO Randy Eresman in reflection of the costs that were experienced in 2010 with Elsie Ross in February, 2011. Ross and Eresman explain that both lower costs of production and higher production levels amounted to reduced supply costs than originally expected and suggest that this trend will continue into the future (Ross and Eresman, 2011). Therefore using a cost of $5 MCF for a delivered cost to KMLNG is a sound delivery cost for natural gas for this assessment. Major discoveries of shale gas reserves, such as the Horn River Basin and Montney basin in Northeast British Columbia, combined with technological improvements in extraction methods have made it more economical to extract shale gas, and have resulted in supply that exceeds the demand for gas in North America. Prices for natural gas have dropped sharply based on the oversupply that is now flooding US markets (Schrier, 2011) and the need for an alternative market for this gas is required. Maxwell and Zhu (2011)
discuss the other possibility for competition with BC pipelined natural gas to the United States. They explain that because natural gas and LNG are substitutes, natural gas prices are expected to be an important determinant of LNG imports. Furthermore, they suggest an increasing share of LNG is traded under short-term contracts with spot shipments being diverted to markets throughout the world offering the highest returns for LNG producers (netbacks). This concept could be exploited when negotiating contracts with potential buyers of LNG from Kitimat.

Relative natural gas prices as well as LNG transportation costs are important determinants of LNG netbacks that could become more prominent should LNG import facilities be built in the US (Maxwell and Zhu, 2011). Concern for BC gas exports to the US in the long term should consider that LNG is projected to become a much larger share of U.S. natural gas consumption, rising from current levels of around 2.5% of total natural gas consumption to 12.4% by 2030 (USEIA, 2011). Also concerning is the future lower LNG value chain costs making LNG from other countries a more viable and attractive substitute for domestic and imported pipeline natural gas from Canada to the US (Maxwell and Zhu, 2011).

2.2 Kitimat Facility

The proposed Kitimat LNG facility will be designed to export Canadian liquefied natural gas (LNG) from new, unconventional natural gas plays in British Columbia and Alberta to the Asia-Pacific region. There currently is a high demand for LNG in Asia and a liquefaction plant constructed on the west coast of British Columbia would provide access to this market. The figure below shows the travel directions from
Kitimat to Asia. Kitimat would be one of the closest LNG export terminals to the Asian market once completed (KM LNG, 2011).

Figure 2: Kitimat would be the closest export facility once constructed. Source: KMLNG, 2011.

The KMLNG joint initiative will include LNG storage and marine on-loading facilities in Kitimat, British Columbia. Initially, the facility will produce five million tons annually of liquefied natural gas (or the equivalent of nearly 700 million cubic feet per day) with plans to eventually double capacity (Apache Corporation, 2011). This is important to this analysis as the profitability of the project can be dramatically affected based on unit volume sold. The project requires regulatory approval from the National Energy Board in order to proceed. As discussed previously, KM LNG was approved by

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Footnote 4: The National Energy Board is an independent federal agency established in 1959 by the Parliament of Canada to regulate international and interprovincial aspects of the oil, gas and electric utility industries. Source: NEB, 2012.
the NEB for production totaling 10 million tons per annum for 20 years (KLOGP, 2011).

The Kitimat port and loading dock are located in a deep ocean location allowing LNG vessels access to the facility as shown in the figure below. The location allows for relatively easy access for LNG tankers that would transport the natural gas by ocean to the Asia-pacific region (KM LNG, 2011).

Figure 3: Representation of the Kitimat LNG Plant once constructed (Apache Corporation, 2011).

The initial cost estimate for the project is stated by Apache to have a construction cost estimate of $3 billion CAN$ (2011) however, the company is currently assessing the project and estimates have the cost of the project as high as 4.5 billion (Apache, 2011). This figure is of utmost importance to the financial viability of the project and will be captured in the economic modeling of this project. Recent analysis has estimated that the Kitimat LNG plant could have an initial production capacity of double the initial proposed 700 Mmcf/day and suggests that the project will
cost $5.6 billion to complete construction (Healing, 2011). Also of consideration are the possible delays that might cause this project to experience overruns. In order for the LNG facility to be 100% operational, the Pacific Trails Pipeline must be finished construction. This project will model the effect of delays in its analysis and emphasize the importance of managing this issue for the companies involved.

2.3 Pacific Trails Pipeline

Kitimat LNG's export terminal will have natural gas delivered through the Pacific Trail Pipelines Limited Partnership's natural gas transmission pipeline system running from Summit Lake, BC to Kitimat. This 463-kilometre, (36 inch) diameter underground line will provide the LNG terminal with a direct connection to the Spectra Energy transmission pipeline system and access to natural gas supplies in British Columbia and Alberta (KLOGP, 2011). The figure below shows the proposed route of the Pacific Trails Pipeline.

*Figure 4: Proposed route of the Pacific Trails Pipeline (KMLNG, 2011).*
The proposed Pacific Trail Pipeline is estimated to have a construction cost of $1.1-billion CANS (Apache Corporation, 2011). This figure differs from the Pardy estimate which estimates a capital cost value of $1.2B USD (2010). This discrepancy is important as the capital decision to fund the project needs to consider the true value for construction of the plant for the viability of the project. The financial analysis in subsequent chapters will assess the viability of this project given the different costs for construction of the pipeline.

2.4 Canadian Natural Gas Supply

Canada is estimated to have 1.7 trillion cubic meters of exploitable, proven natural gas in reserves as of the end of 2010 (BP, 2011). This represents approximately 1% of the natural gas that is available for production throughout the world. In contrast, the United States has approximately 7.7 trillion cubic meters of proven gas reserve that is being developed more actively in recent years with technological advancements in shale gas horizontal drilling (BP, 2011). The Canadian Association of Petroleum Producers (CAPP) indicate that the Horn and Montney plays located in Northeastern BC are estimated to contain approximately 262 trillion cubic feet of natural gas. After conversion, this equates to 7.419 trillion cubic meters of natural gas, a figure that is well above the figure that is presented by BP above. Disparities in reserve amounts are of controversy with the new unconventional gas that is being developed and is an area of debate amongst natural gas analysts and geologists. These plays are referred to the Montney and Horn River basins are located in Northwestern B.C. and can be seen on

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5 Natural gas “Plays” are geographical areas where there are proven or potential natural gas reserves that are being considered for development.
the North American shale play map below (CAPP, 2011). Figure 6 below shows the current known shale plays that are active as of 2011 in North America.

Figure 5: Current Shale Plays in North America (USEIA, 2012).

What is evident when looking at this map is the vast extent of shale gas reserves in North America. Although there are potential issues in accessing all of the natural gas in place, this perspective shows the expanse of the vast natural gas resources available to Mexico, Canada and the US.

2.5 North American Energy demand

Energy demand in North America has been changing over the past several years due to the increased availability of shale gas in the United States and Canada through shale gas technological advances. Natural gas has long since been one of B.C.’s top valued exports and has been vital to regional and provincial economies. Since 2009,
erratic pricing has affected the value of gas exported from BC that is shipped to Alberta and the United States. Natural gas prices are a function of market supply and demand and fluctuate due to these economic forces. Due to limited alternatives for natural gas consumption or production in the short run, changes in supply or demand over a short period often result in large price changes to bring supply and demand back into balance (USEIA, 2012). In 2010, Schrier (2011) summarizes that there was a 16.5% slump in natural gas values from the previous year received by natural gas producers from Canada to the US. Interestingly, the largest global consumption increase of natural gas was in 2010 and occurred in the U.S. (+21.7%), where shale gas developments have kept natural gas prices low. Figure 7 indicates the quantity of natural gas exported to the US from Canada as outlined by Statistics Canada from 2001 until 2010 inclusively.

Figure 6: Natural Gas Exported from British Columbia to the US - 2001 – 2010 Source: Stats Canada, 2010.
This figure illustrates the static demand for BC Natural gas over the past decade even after the most recent technological advances in shale gas. Due to the oversupply of natural gas in the US future demand for BC gas exported to the US may soften and an alternative market would need to be developed. As indicated, natural gas has been one of B.C.'s top exports for many years and will continue to be in some demand even with the transfer of BC gas to LNG on the world market. Of interesting note, the decline in values of natural gas prices to the US from Canada in 2010 was entirely due to a fall in price as the volumes shipped actually increased 12.4% from 2009 to 2010 (Statistics Canada, 2011). Another interesting trend is that US demand (consumption) has actually increased over the past decade for natural gas. As shown in the figure 8 below, since 2006, the US has trended upwards in their consumption of natural gas.

Figure 7: US consumption over the past 10 years 2001 – 2010 (source: BP, 2010).

In 2010, Canada exported 92.4 billion cubic meters of natural gas to the US (BP, 2011). This amount was 7.4% of total US consumption for this calendar year. Of this
amount, BC accounted for 13.1% of total natural gas exports to the US in 2010 or 12.1 BCM (Statistics Canada, 2011). At the current rate of development, BC could develop natural gas resources for the next 125 years (1500 BCM / 12.1 BCM = 123.96 years).

Comparatively, in 2010, Alberta accounted for 81.7% of total natural gas exports to the US in 2010 or 75.5 BCM (Statistics Canada, 2011). Figure 9 below shows the total US export of natural gas to the US from Canada by province. As shown in the chart, Alberta currently exports the majority share of natural gas from Canada to the US.

**Figure 8: Relative amounts of natural gas exported to the US by province in 2010 (Statistics Canada, 2011).**

As discussed earlier, of concern for the BC natural gas industry is the relative availability of natural gas becoming available through shale gas technologies and trends for low pricing of natural gas in the US in the indefinite future. Natural gas inventories have been at record highs and ended December 2011 at an estimated 3.5 trillion cubic feet (TCF) in the US, which is about 12 percent above the same time last year (USEIA,
2012). The average Henry Hub natural gas spot price\(^6\) forecast is $3.53 /MCF for 2012. This represents a decline of almost $0.50 per MMBtu from the 2011 average spot price which had BC producers slowing operations due to negative profit margins. The USEIA (2012) expects that Henry Hub spot prices will average $4.14 per MMBtu\(^7\) in 2013 suggesting there is not relief expected given the current market situation. As shown in figure 10 below, the current price as of January 2012 is below $2.50 / MMBtu which further exacerbates the problem for producers in BC. At these prices, Canadian producers of natural gas will experience losses and be forced to curtail operations.

**Figure 9: Henry Hub price for natural gas Jan. 2010 until Jan. 2012 (USEIA, 2012).**

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\(^6\) The Henry Hub is the pricing point for natural gas futures contracts traded on the New York Mercantile Exchange.

\(^7\) One MMBtu of natural gas is approximately equal to a MCF with a conversion factor of 1.03.
US production has grown steadily since 2005 as indicated in figure 11 and it is reasonable to expect the US gas market to become more self-sufficient over the next few years while demand catches up with supply (BP, 2010). Currently, improved distribution of gas has made possible a wide variety of uses in homes, businesses, factories, and power plants throughout North America. In 2008, for example, the U.S. consumed 23.2 trillion cubic feet of natural gas, nearly one-quarter of U.S. energy consumption and the energy equivalent of almost 190 billion gallons of gasoline. This trend is expected to continue well into the future and all indications suggest that natural gas consumption will grow well into the future (USEIA, 2011). Figure 11 below outlines the consumption of natural gas in the US up to 2008. As this figure suggests most uses of natural gas in the US are growing with the increased availability and reduced price.

Figure 10: Historical usage of natural gas in the United States. Residential and commercial consumption have remained relatively constant over the past 35 years, while use for electricity generation has expanded greatly since the 1990s. Source: USEIA (2011).
As discussed by Maxwell and Zhu, US natural gas consumption and Henry Hub spot prices are strongly correlated (2011). They discuss that as LNG value chain costs decline on the world market, LNG imports have been found to increase proportionately. This pressure will continue in the future for the US as natural gas fired power generation continues to replace coal and other forms of electric power generation as currently is the case in China. Demand and supply imbalances will likely continue to cause volatile gas prices both low and high; however, with lower LNG value chain costs worldwide, LNG has become a viable and attractive substitute for domestic and imported pipeline natural gas in North America.

As shipping technology improves and transport costs fall for LNG, imports are likely to increase to the US relative to dropping natural gas prices (Maxwell and Zhu, 2011). In 2010, US production of natural gas peaked at 611.0 BCM up almost 5% from the previous year (BP, 2011). If this trend continues the US will become increasingly more self-sufficient for their demand of natural gas and as a result, BC and Canadian producers should expect to be squeezed out of this market. In the analysis, the opportunity cost that is being given up would be to continue to compete in the US for a market share of natural gas. Unfortunately, due to the major correction in this natural gas market due to overabundant supply in the US, will be slight erosion from the existing traditional production flows. In the short-term, the side effects of moving natural gas from BC and Alberta to Pacific Rim LNG will have slight affects to the North American natural gas demand. This production as shown in figure 11 below,
along with Canada’s production of 159.8 BCM has resulted in a situation where there is an excess supply of North America natural gas.

Figure 11: US production over the past 10 years 2001 – 2010 (source: BP, 2010).

2.6 World LNG Market

The global LNG industry is in a state of change and many emergent players are looking to gain access or grow capacity in this sector over the next few years. The industry is poised to grow strongly in the long term but due to the recent recession and aggressive competition from alternative sources like shale gas most companies are using caution in expansion into LNG (USEIA, 2012). Globally, the LNG marketplace has 19 exporting countries and 23 importing countries as of the end of 2010 (BP, 2011). As shown in figure 11 the Asia Pacific region imported far more LNG than all others in 2010 and this is positive for Kitimat LNG. LNG is priced in Asia typically using the Japan crude cocktail (JCC) price, or the average price for customs-cleared crude oil imports, which is used as the benchmark for LNG prices for Japanese and Asian buyers.
The prices for LNG have typically followed the global price of oil however after 2008 the indices for the two commodities has separated with prices well above oil comparatively. The price of LNG is typically priced at 10 – 15% of crude oil but in recent months, this price has swung upwards in Asia dramatically due to increased demand (McAllister, 2011).

Figure 12: World LNG market import values by region as of 2010 Source: BP, 2011.

There are certain considerations that may suggest that an increase in LNG imports to this region may be probable when looking at recent data and occurrences. The earthquake in Japan that damaged some of the country’s nuclear power plants has caused societal pressure to move away from nuclear power sources and has increased the demand for LNG as a replacement fuel in this country (Schrier, 2011). One example of increased LNG imports were in July of 2011 where Japan reported the fourth-highest level of import and marked a record high for the summer season, as utilities in Japan ramped up gas-fired power generation to offset a near-record low in nuclear plant
utilization after the atomic disaster in Fukushima, Japan (Tsukimori, 2011). The problems seen at Japan’s nuclear plants during the tsunami disaster may renew opposition to nuclear power worldwide, which may cause a shift toward natural gas as an energy alternative. Further, Japan’s trade values for natural gas have been rising over continuing demand in that country (see fig 12 below).

Figure 13: Japan LNG Market Values / MMbtu in USD Source: BP, 2011.

Other societal pressures are occurring in other countries other than Japan. China is looking to reduce green-house gas emissions by moving away from using coal and switching to natural gas (USEIA, 2012). China's domestic energy strategy should offer some encouragement for LNG producing countries in the long term. The Chinese government has set an ambitious target of increasing the share of gas of the energy mix from 6% to 10% by 2020. The International Energy Agency (IEA) has determined that China's demand will soar by 5% a year, to 274Bcm in 2035 (Petroleum Economist, 2011). With this trend expected, global LNG demand will continue to grow well into the future, especially in Asia where energy demand is growing at the greatest rate and
the greatest shortages are expected. India is another country with growing demand for LNG where population and increased use of energy age growing on a constant basis. Given the huge population that these Asian countries represent, there is the potential for substantial growth in demand for natural gas, which would certainly work in favor for negotiating a deal for Kitimat LNG. China, in particular, has seen its LNG demand grow from 1 BCM / year in 2006 to around 13 BCM / year today and growing (BP, 2012). Figure 13 below illustrates the relative demand for LNG across Asia.

Figure 14: Asian LNG Market Import Values BCM in 2010. Source: BP, 2011.
3.0 Methodology

To determine the NPV for the KMLNG project from an industry perspective, the base case determined the predicted cash flows for the analysis. For consideration, existing LNG deals were identified and the elements of these LNG supply deals were adopted to analyze the potential financial aspects. To predict realistic spot rates that could be expected for the duration of the initial contract period of 20 years, the price of LNG was predicted using the Japanese Crude Cocktail value that ranges between 10-15% of the Asian value of crude oil on the world market. The US Energy Administration future values for crude oil were used and a 12% factor was assigned to determine the table 4 values later in this chapter. These values are essential to the accuracy of this assessment as they outline the relative compensation that would be expected for LNG from an Asian buyer using the existing pricing methodology for LNG. It should be emphasized that this analysis assumes spot rates for LNG using the existing pricing methodologies that are currently in practice. Should a potential buyer be interested in longer-term forward rates for LNG above those rates in table 4, the KMLNG proponents would be recommended to accept these rates for more financial certainty for the project.

After cash flows were determined as shown in table 4, the NPV from an industry perspective was calculated using projected costs for the construction of the KMLNG plant and the Pacific Trails Pipeline, made available by the Kitimat LNG limited partnership group. Operating costs for the development of natural gas reserves and the
transportation of natural gas to the KMLNG site were also considered using figures that were developed from industry reporting and releases of industry information. Taxes and Plant depreciation were assigned using 2012 taxation rates and laws that were in place at the time of this project. Costs for Plant operation and maintenance were also considered in the analysis and were appreciated with the projected rate of inflation at 2.5%. A flat discount rate of 10% was used in the original calculation and this rate is consistent with the discount rate for assessing industry projects from Boardman's (2011) perspective. After the Industry NPV was calculated using the variables discussed above, different simulations of the NPV calculation were isolated to assess the relative effects for changes in specific variables such as reduced rates for the gas, the effect of doubling the production for KMLNG for the analysis, the delay in production for the KMLNG plant over the first 2 years, and the effect of increased fixed costs on the analysis. These outcomes are shown in table 6 later in the chapter and show the sensitivities of the project given a change of a single variable. Further, they offer areas for attention for the proponent should the final investment decision be made to move forward.

Another consideration for KMLNG is that the social costs have not been brought into the analytical discussion and need to be considered from a social perspective. To do this the social NPV using elements that are considered to have standing are determined. To complete a Cost-Benefit Analysis (CBA), an analyst uses the benefit-cost ratio to determine the advisability of undertaking certain projects (Boardman, 2011). Different cost elements were considered for the CBA. Water used in hydraulic fracturing for the production of gas was one of these elements, and was considered using figures that were
available by the Oil and Gas Commission of BC. These amounts were averages in 2012 that equated back to the volume of gas produced assuming no change in technology. Should the amount of water decrease in the production of unconventional gas, the NPV of the system would be greater from a social perspective as this cost would decrease over time. Boardman (2011) outlines the “plug-in” values for the loss of use of water from a societal perspective, and this figure was used to determine the cost to society for the gas production over time. Other costs to society in gas production for KMLNG include areas that are degraded over time for use as industry sites for the development of natural gas. The areas of these sites were calculated through assessing industry information for the KMLNG site and PTP areas, as well through industry averages for well sites, facility sites, and pipelines that industry currently builds on an ongoing basis. These areas were tabulated and a ratio of overall footprint was estimated given recent parameters. These areas allowed for the calculation of the fixed area at the start of the project for the PTP and the KMLNG plant site as well as ongoing developments in the peace region for gas sites for development. The “foot-print” that was determined does not take into account the reclamation efforts that are occurring on some sites and would therefore have an opportunity to be a lower cost over time for the analysis. Costs such as the loss of use of land for public enjoyment as well as the effects to species are also plug-in values that Boardman (2011) offers a methodology for monetization that assume the areas that oil and gas will take up through time should the KMLNG plant move forward. The cost of air pollution in the form of CO2 was also considered and these rates were given standing in the CBA using plug-in values.
The appropriate selection and determination of discount rate was also considered as part of this analysis for both the social and industry perspective. To select an appropriate discount rate for the industry NPV the Capital Asset Pricing Model was used. This allowed the element of risk to be considered for the KMLNG project. The social discount rate that was used from Boardman was further adjusted using a risk factor to calculate a specialized discount rate for the KMLNG project from the social perspective. In calculation, the social NPV for KMLNG considered benefits such as the expected employment that would be generated based on industry averages at the time of the study. Average incomes for the sector were calculated using government statistics data for the oil and gas sector. Assumptions that trends in the amount of employment generated and the incomes increasing with a fixed inflation rate of 2.5% were assigned to the analysis. Royalties and taxes were not appreciated through time and were kept static with rates relative to volumes of gas produced for 1010 thru to 2012 and were calculated on a 1:1 basis with published BC government 2012 figures. One of the outcomes for this project is to consider the potential royalty and tax rates that could result from KMLNG and make recommendations for consideration should the project move forward.

3.1 Base case LNG deals

In order to examine the potential feasibility for the Kitimat LNG project, information regarding a potential rate to be negotiated must be determined over time. In January 2011, Australia Pacific LNG signed a binding agreement to supply Chinese state-owned Sinopec with 4.3 million tons of liquefied natural gas a year for 20 years.
This is a good benchmark deal that would be equivalent to the potential deal with an Asian consumer and the KMLNG partnership. The first analysis that will be investigated is the breakeven cost of a proposed contract rate per unit volume of gas to be feasible given the variable and fixed costs of the Kitimat project. What are notable are the importance of the currency exchange rates and the terms of payment with the different LNG deals. Currently dozens of LNG supply agreements have recently been negotiated or are close to being so. Although the financial aspects for these deals are not readily available, financial analysis can be calculated given the information provided. The Australia Pacific LNG / Sinopec – China deal is summarized in table 1 below.

Table 2: Australia Pacific LNG with Sinopec - China. Source: UPI, 2011

<table>
<thead>
<tr>
<th>Unit Volume</th>
<th>Conversion Factor</th>
</tr>
</thead>
<tbody>
<tr>
<td>4.3 M tones / year</td>
<td>48.7</td>
</tr>
<tr>
<td>209.41 BCF/year</td>
<td>0.001</td>
</tr>
<tr>
<td>209.410 MMcf / year</td>
<td>/365 days</td>
</tr>
<tr>
<td>573.72 MMcf / day</td>
<td></td>
</tr>
<tr>
<td>20 year deal - 90 billion AUS $</td>
<td></td>
</tr>
<tr>
<td>4.5 Billion year</td>
<td></td>
</tr>
<tr>
<td>$21.49 / MMcf</td>
<td></td>
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</tbody>
</table>

When this investment is considered with the information provided, the initial compensation of $21.49 seems to yield a positive investment. However, future cash flows must be discounted and the time value of money needs to be considered for this investment. Other proposed prices for gas to India are being proposed by companies such as Cedigaz in Qatar. Recent proposals for supply to India are around the $13.00 / Btu mark however, India has negotiated lower rates in the past and analysts are suggesting the price should be in the $10.00 / Btu range (Petroleum Economist, 2011). The value of the deal shown above shows gross revenues for the project and does not
disclose the negotiated forward rates for LNG on the world market. Another comparable investment that should be considered for the KMLNG project was recently negotiated between Exxon Mobil and PetroChina.

Table 3: Exxon Mobil Corporation /Petro China LNG Deal. Source: Gelsi, Marketwatch, 2009

<table>
<thead>
<tr>
<th>Unit Volume</th>
<th>Conversion Factor</th>
</tr>
</thead>
<tbody>
<tr>
<td>2.25 M tonnes / year</td>
<td>48.7</td>
</tr>
<tr>
<td>109.575 tccf / year</td>
<td>0.001</td>
</tr>
<tr>
<td>109575 MMcf / year</td>
<td>/365 days</td>
</tr>
<tr>
<td>30.62 MMcf / day</td>
<td></td>
</tr>
<tr>
<td>20 year deal - 4.1 billion AUS $</td>
<td></td>
</tr>
<tr>
<td>20.05 Billion year AUS $</td>
<td></td>
</tr>
<tr>
<td>518.71 / MMcf AUS $</td>
<td></td>
</tr>
<tr>
<td>Over 20 years**</td>
<td></td>
</tr>
</tbody>
</table>

3.2 NPV Calculations for Project – Industry based

The first consideration in looking at the Kitimat LNG decision is to assess the relevant cash flows that would be expected should the project be constructed and possible aspects of a long-term contract benchmarking off existing LNG deals. As previously suggested, this project will examine current rates for agreement and make suggestions for the rate that should yield a positive investment. The analysis will follow the stand-alone principle where the incremental cash flows from KMLNG are assessed solely against the costs of the PTP line and liquefaction plant alone, leaving costs for production of natural gas to be a separate line item that can be managed on its own (Ross et. al., 2007). Further, sunk costs for other mega projects such as regional pipelines and gas plants will be accounted for with the variable cost calculations. McAllister refers to the market situation for LNG demand and the rates that can be expected for deals with Asia (2011). He outlines how demand in Asia is trading at 4 times the North American Henry Hub spot pricing for the equivalent volume of LNG.
This reference is to the Asian spot LNG prices are now around $11 per million British thermal units as compared to below $2.50 mark in the US (McAllister, 2011).

The term benchmarking refers the process of determining who is the very best, who sets the standard, and what that standard is for in the business world (Reh, 2011). As shown above, Australia PNG and Exxon Mobil Corporation were recently successful at signing deals for Australian for 20 year LNG supply deals. Australia is one of our main competitors for LNG business on the world market and in order to find a competition point and starting point for negotiations, a LNG firm entering the world market must consider current demand elements for negotiation of a contract. One aspect that is of vital importance to this decision is the currency conversion factor. If we assume that the Canadian dollar will remain steady over the next 20 year period relative to the US$ then there would not be an advantage negotiating compensation in US$ / unit volume. Production costs to move the raw natural gas to the terminal and conversion costs to turn the gas to LNG are all paid at Canadian dollars. There could be substantial gains or losses depending on the currency conversion with the prospective buyer. At the time of this study, the value of the Australian dollar was more than the Canadian dollar and has been so for roughly the last 6 month period. If we take an average of the two Australian values and convert them to Canadian dollars as of January 1st 2012, there is a good analysis point for a potential rate of compensation should Kitimat LNG sign a deal. An assumable contract for Kitimat would be somewhere around $12 Canadian / MCF / 20 years with an appreciated value based on the price of oil assuming that the terms of the contract follow typical reference to the Japanese Crude Cocktail pricing. If we consider the EIA (2011) projections for the price of crude oil into the future,
negotiated values for LNG can be calculated based on the 10% to 15% value previously discussed.

Assuming that this was a potential negotiated rate for the Kitimat LNG, we can continue on to calculate the NPV for the Kitimat LNG facility. The terms of the payment rates through time would be important and the option to lock in forward rates or budget on spot rates to be considered. Options to begin compensation at a lower rate and to step the rate up to match inflation would be probable, given comparison to other negotiated LNG deals that have taken place. A purchase agreement that allowed for a higher rate of compensation earlier on in the contract would be beneficial for the sellers and not the purchasers as the calculation needs to consider the time value of money.

With the trade of LNG on the world market, prices are typically sold using spot rates which set a price that is quoted for immediate settlement on a commodity, normally negotiated one or two business days from trade date. LNG is also traded using
forward rates where the cash market transaction in which delivery of the commodity is deferred until after the contract has been made. Although the delivery is made in the future, the price is determined on the initial trade date for a long-term contract. The disadvantages with forward rates for LNG are that the price could go up leaving margins that are not capitalized. The benefit is that the risk involved with dropping spot rates is removed as you are locked on for rates for the commodity in question (LNG).

The net present value of an investment is defined as the measure of how much value is created for a firm today by the decision of taking on an investment at a specific time in the future. It is the difference between the present value of the future cash flows from an investment and the amount of the original investment (Ross et. al., 2007). The present value of the expected cash flows is computed by discounting them at the required rate of return and uses the following formula:

$$NPV = I_0 + \frac{I_1}{1 + r} + \frac{I_2}{(1 + r)^2} + \ldots + \frac{I_n}{(1 + r)^n}$$

For the Kitimat proposal, the net present value was computed in Canadian dollars as the US dollar was at parity at the time of the assessment. Exchange rates through time will be a consideration in negotiating a deal with an Asian buyer as future spot rates for exchange between the two parties should be negotiated.

### 3.3 NPV Calculations Base Case Scenario

The following incremental rate structure shown below would be probable given the current price of LNG on the world market and the overall value of the two previous 20-year deals for supply of LNG. The projected cash flow statement for Kitimat LNG
project could be based on the incremental rate structure based on inflation / time. The first variable in computing the NPV for Kitimat is the total sales that are expected. As stated before, LNG is typically priced on the cost of crude oil. If the EIA reference case for crude oil shown in figure 14 is used and we assess the conversion factor to be 12% the price of crude (as it is currently) then the following spot rates are expected for Asia LNG:

Table 4: KMLNG LNG Rates - Base Case on EIA oil projections

<table>
<thead>
<tr>
<th>Possible Rate structure</th>
<th>Rate / MMcf</th>
<th>Year</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>$12.84</td>
<td>2015 - 2020</td>
</tr>
<tr>
<td></td>
<td>$14.40</td>
<td>2020 - 2025</td>
</tr>
<tr>
<td></td>
<td>$14.70</td>
<td>2025-2030</td>
</tr>
<tr>
<td></td>
<td>$15.00</td>
<td>2030-2035</td>
</tr>
</tbody>
</table>

The rates in table 4 are based on the projection by the EIA for values 2015 - 2020 $107 crude, 2020-2025 $120 crude, 2025-2030 $122.50 crude, 2030-2035 $125 crude. In the NPV calculation if the case, sales are calculated by multiplying unit volume multiplied by cost per unit volume. The rate structures in table 4 are values that could be negotiated for the KMLNG project when considering recent deals to provide LNG for 20-year periods worldwide. These values are referred to as the base case\(^8\) for the purpose of this study and assume no delays and spot prices for LNG based on current and future economic conditions. The rate was set to rise incrementally as the

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\(^8\) The Base Case is the business case that utilizes a type of decision-making tool used to determine the effects a particular decision will have on profitability using an initial set of parameters. A business case should show how the decision will alter cash flows over a period of time, and how costs and revenue will change. Specific attention is paid to internal rate of return (IRR), cash flow and payback period which is captured later in the study (Ross et. al., 2007).
deal moves forward through time. This would accommodate the costs of inflation and would have dramatic effects for the overall profitability of the project. In the first year of sales, the gross revenues are as follows: 255,500 MMcf/year × 1,000 × $12.84 = $3.28 billion in gross revenue. As we discussed before, the breakeven production costs for Northeast BC were valued at $4.00 per MMcf in 2012 for shale gas produced. This amount includes the costs for transmission through the Pacific Trails Pipeline and the Spectra transmission line in the amount of $1.00 MMcf for throughput pipeline costs to transport the natural gas. A $4.00 variable cost of production is then appreciated at 2% inflation per year to yield a variable cost of production at $4.24/MMcf in 2015 for gas brought to the KMLNG terminal from Northeast BC. The total variable costs in 2015 were calculated at $1.084 billion to meet the full capacity for KMLNG facility.

Depreciation for the plant was calculated using accelerated depreciation following CRA rules (CRA, 2012). The residual value of the plant was not computed and the lifespan of the project was estimated at 20 years. Fixed costs for gasification, conversion costs, and plant operating costs were determined through market research to be between 20-30% of operating revenues. This figure is consistent with other LNG facilities throughout the world. Corporate taxes were also calculated using a fixed rate of 22% and are deducted off the EBIT in the calculations. Net revenues for 2015 after the initial capital investment in 2013 of $4.2 billion were $0.908 billion indicating good margin for the project. The internal rate of return for this project or the discount rate that makes the net present value of all cash flows from a particular project equal to zero is 23%. The NPV for this project is $4.46 Billion with a breakeven period of 6.2 years at a discount rate of 10%. This calculation does not consider possible challenges with the
project such as delays in construction, reduced rates in global LNG prices or worker shortages that could have negative results to the base case. Regardless of these potential challenges, the results for the NPV analysis of KMLNG look very good in the short and long-term. The discount rate that was used does not take into account the inherent risk of the project and different simulations will be used in Chapter 6 to assess different discount rates taking into account average returns in the stock market along with the risk that is involved with ventures in the natural gas sector.

3.4 NPV Calculations Reduced Rates

In researching this project, there are several instances where the data and reference materials were in disagreement. Production delays, cost over-runs, reduced rates for long-term supply agreement and increased fixed costs are all realistic scenarios that could be possible for KMLNG. If we change the rate of the long-term supply agreement as follows we will have the most dramatic changes to the profitability of the project. Figure 14 above shows the EIA (2011) projection for the world price of crude oil for a low oil price of $50 / barrel by 2035. This projection shows the low value of oil should other market disruptions occur that make oil devalue into the future. The following would be considered at the low end of current 20-year LNG deals using the projection data for crude oil from the EIA (2011):
At these rates the financial outlook for Kitimat LNG is very different than the base case scenario above. Given these rates, the NPV is \(-\$3.0\) billion, the IRR is negative and the profitability index is \(-0.71\). At these rates of compensation for KMLNG, the project would not be feasible unless the variable costs of production could be reduced substantially.

### 3.5 NPV Calculations - Cost Over-Runs, Production Delays and Increased Fixed Costs

The next simulation to be investigated is the result of higher initial investment for the project with the incremental effects of cost over-runs, production delays over the first two years, and increased fixed costs. As stated earlier in the project, the KMLNG project is being assessed for its final estimate for construction costs. This figure was estimated to be \$3.0 billion originally but has been estimated to be potentially \$5.2 billion by certain projections. The PTP also has been estimated to cost \$1.2 billion at the high end. If we calculate this capital spending for the project calling this cost over-
runs we will have an obvious different result and these costs need careful consideration before the decision to accept the project is made. To determine the effect of the initial costs being $6.4 billion instead of $4.2 billion, the adjustments were made in the capital budgeting analysis.

Table 6: KMLNG NPV Analysis Outcomes

<table>
<thead>
<tr>
<th>Scenario</th>
<th>NPV at 10% D.R. $Billions</th>
<th>IRR</th>
<th>Discounted Payback Period</th>
<th>Profitability Index</th>
</tr>
</thead>
<tbody>
<tr>
<td>Base Case</td>
<td>$4.46</td>
<td>23%</td>
<td>7.2 years</td>
<td>1.06</td>
</tr>
<tr>
<td>Reduced rates</td>
<td>$-3.09</td>
<td>0%</td>
<td>n/a</td>
<td>-0.72</td>
</tr>
<tr>
<td>Increased Fixed Costs</td>
<td>$2.30</td>
<td>17%</td>
<td>9.8 years</td>
<td>0.54</td>
</tr>
<tr>
<td>Production Delays</td>
<td>$3.89</td>
<td>17%</td>
<td>8.3 years</td>
<td>0.54</td>
</tr>
<tr>
<td>Double Production</td>
<td>$11.40</td>
<td>32%</td>
<td>5.3 years</td>
<td>1.84</td>
</tr>
</tbody>
</table>

The result of the extra $2.2 billion in capital spending for both projects is shown above in table 6. What is shown is the project is still profitable should costs escalate and the project has good margins should the rates be negotiated at the base case amount. Production delays and challenges in completion are commonplace with a large-scale industrial project such as KMLNG. If we make an adjustment to the first year’s production of 75% of full capacity and the second year 90% of full capacity, then a margin for initial start-up problems will be considered as a possible outcome. Production delays would have the least affect to the profitability as shown in table 6 above but would be the easiest issue to avoid with careful planning and competent management of the projects. Finally, as discussed earlier in the project, the fixed costs with running a LNG facility can vary based on the cost of energy and labor in the operating jurisdiction. To adjust this factor from 20% to 30% represents a realistic adjustment for the possible increase in operating costs for the plant. This rise in costs
had the most substantial change in the system and should be closely analyzed in making the decision to invest. There could be a real savings for the project with investing in more expensive, sophisticated technology to keep the fixed costs for the plant down. Future analysis of upgrading the configuration and running the plant on Natural gas versus electricity are all considerations that KMLNG should investigate.

What is evident when looking at the results of this analysis are the effects for KMLNG should different financial variables change through time. This information also provides financial and executive leaders with key focus areas for supply chain management and overall project management for KMLNG. The first and most important aspect for the project are the negotiated rates and currency conversion factors as seen in the reduced rates calculation. If the project has a supply agreement with rates approximate to table 5 above, proceeding with Kitimat would be a poor investment decision, regardless of other variables associated with the overall cost.
Chapter 4
SOCIAL AND ENVIRONMENTAL IMPACTS

4.1 Social Impacts of Kitimat LNG

One of the potential impacts that will be a result of the decision to move forward into the LNG market place for British Columbia is the creation of jobs and the increased revenues that will be generated as a result of the increased industrial activity. As discussed earlier, BC currently produces approximately 12 BCF of marketable gas per year which acts as a major economic driver for the province. But what are the costs that are associated with the creation of LNG in British Columbia for shipment throughout the rest of the world? When looking at the project from a social perspective, this analysis will use the stand-alone principle maintaining that the effects from KMLNG are based on the cash flows to BC independent of other cash flows that would be generated (Ross et al., 2007). The first relevant cash flow that would be generated from KMLNG is Royalties. As discussed in chapter 5, Royalties per MMCF of natural gas produced is approximately $2.00. KMLNG is planning on consuming 255,500 MMCF / year suggesting that the income using current figures would be $511,000 / year at today’s figures. This figure would have to be inflated through time and will be increased by 2% for the analysis to represent inflation.

Another revenue stream for BC would be the income tax that would be generated from an operator of KMLNG. Using the figures generated in the previous analysis, the taxation income would be $256.3 million in 2015 alone. Income tax from workers would also be revenue for the crown as a result of the project; however, the
social benefit will be computed for income alone. This income would be for both the
construction of the projects initially as well as for the ongoing income tax provided for
ongoing maintenance and production workers on the plant.

4.2 Cost -Benefit for Kitimat LNG

Costs to British Columbia with KMLNG could involve the creation of carbon
dioxide in the liquefaction process. This cost is known as a negative externality and
needs to be accounted in order to calculate the net cost of production. The KMLNG will
most likely be powered directly by BC electricity for the liquefaction process and
therefore this externality need not be completed. Baye (2009) outlines that the creation
of pollution such as CO2 is a negative externality that needs to be accounted for. In the
case of KMLNG, the plant will run on electricity as the costs would be much higher for
LNG plants that run on natural gas. The producer (KMLNG) would not pay for this
pollution given the current requirements for operations should the decision be made to
run the liquefaction process on natural gas as well as the increased cost of consuming
materials that could be used to produce end product for the plant. Furthermore, the
costs of producing LNG plants that consume natural gas instead of raw electricity are
much more expensive to construct (UPI) (2011).

One option that BC has is the option of imposing a carbon tax for KMLNG
based on LNG that is exported. The tax rates on July 1, 2012 were increased from $25
to $30 per ton of CO2 equivalent emissions by the BC Ministry of Finance
(Government of British Columbia, 2012). A typical LNG liquefaction terminal

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9 Externalities occur when firms are not held accountable for the true cost of conducting their economic activities (Baye, 2009).
exporting 4.5 million tons of LNG can be expected to produce 1.5 million tones of equivalent carbon dioxide of direct emissions by the end user of the natural gas (FERC, 2012). As shown in table 3 earlier, KMLNG would produce 5.25 tons of LNG / year resulting in 1.4 tones CO2 emitted / year. At the current carbon tax rate, BC could amend the legislation to capture a tax for the CO2. This option would allow for taxation of all gas shipped from BC regardless of the location of production (Alberta). Other costs are the areas taken up for the construction of the PTP and the KMLNG site. However, the site of the plant was purchased and its assessed regional taxation will be assessed to the company (KMLNG, 2011). Costs of producing natural gas in Northeast BC are not admissible as it would not follow the stand alone principle for analysis of the project (Ross et. al., 2007). This would involve a separate analysis of regional natural gas production for domestic uses and for export to the US.
5.1 Current Royalty Rates and Programs

Currently, royalties for natural gas produced from a Crown lease in British Columbia are collected by the Ministry of Finance on behalf of the province. The royalty regime for BC natural gas is structured to maximize the amount of economic rent collected from natural gas, while ensuring that producers are able to earn a fair return on their investment (GOBC, 2010). Economic rents from oil and gas have fluctuated in value over the past 10 years and are determined using the Henry Hub cost averages in the United States. Royalties on (MCF) of production in BC have moved from $0.92 to $1.95 between 2000/01 and 2008/09 meaning that depending on the year, producers have paid average royalties to the Crown between $0.92 and $1.95 per thousand cubic feet (MCF) of natural gas produced and sold to markets (GOBC, 2010). Figure 14 shows that relationship between the royalty rates for the province based on the value of the gas in the marketplace.
This data shows the effect of change in policy in 2003 / 2004 to encourage industry spending in the oil and gas sector. Previous to 2005, BC claimed a higher royalty rate for gas produced relative to the marketable price for that volume of gas. After the royalty program, (from 2005 and beyond) the government claimed less royalties due to the royalty program and subsidized more challenging investments. The royalty programs aimed to ensure that British Columbia’s natural gas royalty regime remained competitive with other jurisdictions such as Alberta, while encouraging development of natural gas (GOBC, 20102). The royalty deduction programs included: producer cost of service allowances, deep well, summer drilling, marginal, ultra marginal, low production, and new pool discovery and road construction. These deductions resulted in deductions of royalties revenues of $444.6 million in 2010 and $610.8 million in 2009 (GOBC, 2010). This equates to approximately half the potential
royalty revenues that could have been collected if the royalty programs were not in
place. These royalty rates are based on the economic values for North America and do
not represent the potential values for LNG on the world market. Average royalty rates
for KMLNG in the short term given the values above will be approximately $1.20
/MCF in the short-term and this is potentially a concern given the new values that
natural gas could be valued at as LNG on the world market (GOBC, 2010).

5.2 Future Royalty Rates and Options

The KMLNG offers a new marketplace for BC natural gas and changes to the
current royalty regime need to be contemplated in order to offer a fair price for natural
gas being converted to LNG. However, BC is in competition for investments in the
natural gas / LNG sector and immediate increases to the current royalty rate structure in
the province should be avoided. One suggestion is to allow market forces to drive
royalty rates into the future. To make this happen, rates could be blended based on the
values for LNG and the natural gas price indices in North America to represent a true
value. Maintaining provincial and global competitiveness for both natural gas and LNG
needs to be a priority for BC. Furthermore, the income tax generated as well as the
increased industrial activity will result in increased revenues to the crown from
KMLNG. Should KMLNG move forward, consideration should be given to the BC
royalty structure, but only after the global values for BC LNG are known.
6.1 Market Demand for LNG

Market demand for LNG has shown to be very strong in the Asian market. The Demand curves for natural gas in both the North American market and for Natural gas in the Asian market are very different; even though the good is the same in both markets and has many of the same uses (hydro-electric generation, heating, etc.). Due to market demand and increased consumer willingness to pay the price for natural gas has become more divergent since 2008 in North America versus Asia. Figure 17 below represents the differences in the current market conditions for natural gas at the start of 2012 in Asia and North America.

Figure 17 Different prices given different demand
As shown in this graph, the increased demand that is being generated in Asia is resulting in the difference in price for natural gas in Asia versus North America. Due to the increased demand in Asia and due to consumption pressures and decreased demand in North America because of chronic oversupply, the distance between $P_1$ and $P_2$ is actually $2.50$ and $14.00$ respectfully. This is due to excess supply in one market and excess demand in another which has resulted in the opportunity for KMLNG.

Another aspect that needs consideration, but are not part of the calculation for KMLNG are the sunk costs that occurred with previous exploration of natural gas, purchase of petroleum rights, and the costs of drilling. Sunk costs are monies already spent and permanently lost due to the original investment decision being made. Sunk costs are past opportunity costs that are partially or totally irretrievable and because of this should be considered irrelevant to future decision making (Boardman et. al., 2008). This term is originally from the oil industry where the decision to abandon or operate an oil well is made on the basis of its expected cash flows disregarding the amount spent in drilling it. Although this cost is not recoverable, due to the lack of market that is available for North American natural gas, companies should be willing to invest based on tighter margins to recover capital that is already been allocated and spent.

6.2 Social Costs Associated with KMLNG

Another consideration for KMLNG is that the social costs have not been brought into the analytical discussion and need to be considered from a social perspective. For example, an estimated $11.1$ billion in costs are involved in air pollution and government subsidy costs associated with forestry, oil and gas, and mining sector
activities; costs that should be deducted from the Canadian market GDP value as environmental and social costs of development with CBA (Anielski and Wilson, 2005). Society will have to provide electricity to KMLNG for liquefaction of the product and also enter into agreement to supply the natural gas for the venture over the long-term. This is an example of a subsidy that could be a cost for consideration in the CBA with the KMLNG but would be difficult to include as rates would be speculative. For this reason the electricity required for the KMLNG facility will not have standing for the determination of the social NPV calculation. Consideration for ongoing natural gas developments that will be considered with this study are: the consumption of water for hydraulic fracturing, the degradation of land for industrial development, the effects to species such as Caribou, and the creation of greenhouse gases such as CO2 need consideration. Future studies using empirical research to set risk premium based on effects to social resource values such as those referenced above (caribou, air quality, water, soil degradation) are areas for consideration and empirical research.

One of the problems for the NPV calculation from a company perspective is that they are inherently biased for the success of the project. Company bias does not consider the cost of the water consumed, the cost of the degradation of the land, the loss of habit of certain threatened species, or the release of greenhouse gases to the atmosphere as a result of the processing of natural gas for LNG transport. For this reason, companies use a balanced approach for the evaluation of KMLNG as they potentially underestimate the risk to social factors. To take these factors into account a Social NPV has to be considered for KMLNG. Cowen (2008) discusses the concept of social discount rate to evaluate future costs and benefits. He suggests that market
interest rates have to be adjusted for taxes, transactions costs, and risk to generate a social discount rate. Although there is much debate as to the rate that is generated, discount rates need adjustment to be context-dependent so that the right mix of costs versus benefits is contemplated for the decision (Cowen, 2008).

The Treasury Board of Canada Secretariat (TBCS) (2007, 1988) are responsible for setting the real social discount rate (SDR) for the evaluation of projects by all levels of government in Canada. With a project such as KMLNG, the methods used by TBSC would seem reasonable; however, there are challenges with using such a high rate for social discounting. The TBCS values are based on the weighted social opportunity cost of capital (WSOC) method. Since 1976, the TBCS has mandated the federal cost-benefit analyst SDR of 10% (TBCS, 2007). Currently, the TBCS has lowered the discount rate to 8% with sensitivity analysis at 3% and 10%; however, Boardman (2009) argues that these rates are set arbitrarily high and need downward adjustment. For KPLNG the social discount rate (S) is needed to discount benefits and costs to their future value. He suggests that if a project is intra-generational (less than 50 years) and there is no crowding out of private investment, then analysts should use an SDR of 3.5 percent. (Boardman et. al., 2010).

6.3 Capital Asset Pricing Model to Assess KMLNG

KMLNG is a consortium capital project where multiple companies are taking the risk of the investment. In order to pool this risk based on the relative riskiness of the project different beta metrics were assessed through assessment on the stock market (Google Finance, 2012). Using the Capital Asset Pricing Model (CAPM), that
describes the relationship between risk and expected return and that is used in the pricing of risky securities, the following beta values were assessed:

EnCana Beta is 1.04, Apache Beta is 1.34, EOG is 1.09, Talisman 1.52, and Quicksilver 1.69.

These companies were selected based on their enrollment in the KMLNG or their involvement in natural gas business in British Columbia. After assessing these companies, the average beta value was determined to be:

Average = 1.34 beta. The risk free rate in Canada is currently: \( R(f) = 1\% \). This value has dropped substantially over the past several years as shown in figure 18.

Figure 18: Risk free rate in Canada since 2002. Source: BOC

![CANADA INTEREST RATE](source.png)

The CAPM equation (Model) is as follows:

\[
E(r) = R_f + \beta [E(R_m) - R_f]
\]

whereby:

- \( r \) = return
- \( R_f \) = risk-free rate (rate of return on a risk-free investment e.g. Treasury bonds)
- \( R_m \) = return rate of the market

\( E(r) \) = expected return on the asset

\( E(R_m) \) = expected return on the market
CAPM is based on the concept that investors need to be compensated in two ways: firstly, based on the time value of money and secondly, on the inherent risk of the project. The time value of money is represented by the risk-free (Rf) rate in the formula and compensates investors for investing money for a given period of time (Ross et. al., 2007). As shown above, this rate is currently quite low at 1%. The risk premium is the (RM - Rf) part of the CAPM equation and is the amount of return that one would receive in excess of the risk free rate - basically, the difference between the risk-free rate and the actual return. It is called a premium because the return that a person would expect to receive on an investment is directly proportional to the amount of risk they take on. Assessing the average rate of return that markets have yielded from January 2001 to January 2012 – the average rate of return is approximately 12% (Google Finance, 2012). Using all this information E(R) is as follows:

\[ E(r) = 1\% + 1.34 \times [12\% - 1\%] = 15.74\% \]

It is therefore warranted to complete a simulation using rates of 14% 16% 18% from and *industry perspective* to take into account the risk of the project. If we refer to Table 6 in Chapter 3, the discount rate of 10% was used for analysis of this investment from the industry perspective. This rate does not properly take into account the risk of this particular investment in this sector. Table 7 represents the simulation of the KMLNG using higher discount rates to properly assess KMLNG.
Table 7: KMLNG Simulation Analysis Outcomes

<table>
<thead>
<tr>
<th>Scenario</th>
<th>NPV $Billions</th>
<th>IRR%</th>
<th>Discounted Payback Period</th>
<th>Profitability Index</th>
</tr>
</thead>
<tbody>
<tr>
<td>14%</td>
<td>$2.34</td>
<td>23%</td>
<td>8.9 years</td>
<td>0.558</td>
</tr>
<tr>
<td>15%</td>
<td>$1.95</td>
<td>23%</td>
<td>9.1 years</td>
<td>0.465</td>
</tr>
<tr>
<td>15.74%</td>
<td>$1.69</td>
<td>23%</td>
<td>9.6 years</td>
<td>0.423</td>
</tr>
<tr>
<td>16%</td>
<td>$1.61</td>
<td>23%</td>
<td>9.8 years</td>
<td>0.382</td>
</tr>
<tr>
<td>17%</td>
<td>$1.30</td>
<td>23%</td>
<td>10.1 years</td>
<td>0.309</td>
</tr>
</tbody>
</table>

What is evident with this analysis is that even with risk included, KMLNG is still a viable project given the discount rates indicated above. What this analysis concludes is that KMLNG has margins that provide acceptable returns with risk factors calculated into the equation.
Chapter 7

SOCIAL COST-BENEFIT ANALYSIS FOR KMLNG

7.1 Using Cost Benefit Analysis to Assess KMLNG

Cost Benefit Analysis (CBA) is a process by which business decisions are analyzed for the associated costs and benefits to develop a balanced decision (Boardman et. al., 2010). Because CBA is a useful tool in assessing these types of projects, this is a good analysis tool for KMLNG. Companies use CBA and other analytical methods to compare investment alternatives and evaluate implications of business decisions. To use CBA, benefits of a business-related decision are first summed and costs associated with taking that action are subtracted to yield a total. In simplest terms, if this equation is positive then the equation suggests moving forward with the decision. One of the benefits of CBM is that it gives an analyst the ability to use a model to put a dollar value on intangible items, such as the benefits and costs associated with undertaking a certain project. Opportunity costs are also factored into CBA equations (Boardman et. al., 2010) and social CBA allows for social costs along with the investment decision.

Boardman (2008) suggests that prior to erecting a new plant or taking on a new project, prudent managers will conduct a cost-benefit analysis as a means of evaluating all of the potential costs and revenues that may be generated if a project is completed. The outcome of the analysis will determine whether the project is financially feasible, or if another project should be pursued.
7.2 Cost Benefit Analysis

As discussed by Boardman et. al. (2010) cost benefit analysis (CBA) is an assessment tool that quantifies in monetary terms the value of a decision to all members of society. A cost-benefit analysis is a comprehensive way of assessing the positive and negative implications of a project before the decision to take on the project is made. To complete CBA, analysts quantify the benefits and use a benefit-cost ratio, which is a ratio of the present value of benefits to the present value of costs to determine the advisability of undertaking certain projects. One note is that investment and operational costs associated with a project are usually easier to define and measure than the benefits. CBA considers all the aggregate of all costs and benefits from a social perspective after they have been appropriately discounted. The following 8 steps, as outlined by Boardman et. al. (2010) can be used to assess KMLNG using CBA:

7.2.1 Specification of Alternative Projects

In this step of CBA the different decision alternatives are discussed. For KMLNG the project is either undertaken or not and the rate of production is set at 700 MMCF / day or 1.4 BCF day (double capacity) (KMLNG, 2011). Boardman (2010) suggests that CBA compares the net social benefits of investing resources in one or more particular potential projects with the net social benefits of a project that would be displaced if the project under evaluation were to proceed. In this case, the project is either undertaken or not and the capacity of the system is determined.
7.2.2 Decision on Benefits and Costs with Standing

This step of CBA involves the decision on whose social benefits and costs should be included. I.E. KMLNG profitability is not standing, although the province is not motivated to see the project fail. The current market value for the natural gas in the North American market is the opportunity cost that is paid in the accounting model. However, this analogy is flawed as there is a diminishing market for natural gas to the US. For this reason, the value of the gas could rapidly diminish and this opportunity cost is very difficult to calculate. For this case, the CBA considers the costs and benefits for British Columbians including the government and Canadians as a whole. It does not discredit the values derived for KMLNG, it simply excludes them to focus on the social NPV. The standing social benefits consist of the following for KMLNG:

Benefits that are standing for KMLNG are:

1. Employment – KMLNG will employ additional persons from the existing natural gas workforce and the displacement or post KMLNG export of BC natural gas exports will be ignored.

2. Royalties – royalty programs that are currently available in BC will be assessed using the CBA assuming the status quo will continue for natural gas that is produced in BC. Recommendations will be provided based on the margins that exist in the system based on economic conditions previous to the project and afterwards.

3. Taxation from business activities that would be taxable for both the Province of BC and the Federal Government.
4. Possibility for the implementation of a Carbon Tax based on LNG that is produced at source for shipment. The BC government currently has a set rate of $30 ton of LNG that could be assessed a Carbon tax.

Costs that are standing for KMLNG are:

1. The total land and areas that will be taken up from their current wilderness state and converted to industrial use.

2. The resulting greenhouse gas emissions (CO₂) that will be created should the decision to pursue KMLNG be decided.

3. Water consumption that will be required for the production of natural gas associated with the needs for KMLNG to operate.

4. Habitat disruption from the lands that will be impacted both now and into the future as a result of the developments to construct the KMLNG plant site and Pipeline along with the ongoing activities in the natural gas region of BC.

5. Loss of use by the public for areas that have recreational capability or the ability to support these activities by the public and are therefore considered a common good.

6. Loss of future value of the gas at the end of the period of the analysis. Natural gas has a finite life span in relation to its overall availability. This project has the potential to mine approximately 10.4% to 20.8% of the known gas resources of the province over a 20 year period.
7.2.3 Impact Categories and Measurement Indicators

For CBA, Boardman et. al. (2010) explains how the analyst has to establish a cause-and-effect relationship between the physical outcome of the project and the utility derived from various population groups. The ability to assess a monetization for the indicator is challenging with this stage of the analysis. As Boardman suggests, stating assumptions and give them appropriate weighting is challenging and there are various models for conducting these assessments. The following benefits were monetized for with KMLNG.

**Direct employment** of 500,000 Oil and Gas workers in Canada (TQM Consulting, 2010). 13% of the industry occurs in BC = 65000 people employed roughly in BC. KMLNG will produce 7.23 BCM / year. 7.23 / 12 = 60.25 % of the BC gas market which is 39163 people employed through Kitimat LNG project / year. Stats Canada outlines the average wage for oil and gas workers in BC is $34.06 in 2010 and this figure has grown by $0.76 since 2009 and $1.77 in 2008 (Statistics Canada, 2012). If we take the average of this increase, and multiply this by the last two years, the average wage in the oil and gas sector in BC is $37.32 in 2012 according to Statistics Canada figures. On an annual basis this amounts to an average wage of $77,636 per year and is the highest paid sector of all industries in BC according to Statistics Canada. As determined above, 39163 people are employed in the sector for both direct and indirect employment. When all this is factored in, the wages alone for the oil and gas sector will generate approximately $3,040,458,668 in income for employees. Many of the employees are employed in other jurisdictions or will travel to BC to work on a temporary basis. Even then, $3.4 billion dollars represents a very large opportunity for
Canadians employed in the BC natural gas sector. For the CBA, we will assign 30% of these benefits to the analysis and income tax. For the sake of the CBA analysis, we will assign 15% of the workforce benefits outside of British Columbia.

**Royalties collected** based on production of the natural gas. Average royalties are 2$ MCF less the royalty program credits that allow for approximately ½ of this amount to be refunded to the operator in the form of Royalty programs. As discussed earlier by GOBC (2010), the average royalties that could be expected from KMLNG would be $1.20 MCF or $840,000 for the plant capacity / day. This would equate to $306.6 million per year of royalty revenue for BC. When looking at the concept of royalties for the natural gas sector, consideration towards the fair royalty for the natural gas has to be considered once gas is being sold in global markets as LNG.

**Corporate taxation** is 22% average in B.C of which 10% is for large companies for provincial tax and 12% is for Federal taxation (CRA 2012). The total taxation for the project was assessed in the financial analysis of the project that was assessed in Chapter 3. For the base case, it taxation for the 20 year period was calculated to be $6.65 Billion Canadian which includes both the Federal and Provincial portion. For CBA this is the amount of the entire taxes that will be generated at KMLNG for the 20 year period and this has standing.

**Carbon taxation** is an option for the BC government to tax companies for the amount of LNG that is produced. The carbon tax applies fossil fuels within the province of BC and is based on the amount of greenhouse gasses emitted when a unit of fossil fuel is burned or consumed. Administratively, the carbon tax is applied and collected essentially the same way that motor fuel taxes are currently applied and
collected as the consumer is taxed at the source of the consumption (BCMF, 2012).

Tax rates on July 1, 2011 were based on $25 per ton of CO2 equivalent emissions, and increased by $5 per ton to $30 per ton in 2012. As discussed earlier, 4.5 tons of LNG that are consumed emits a total of 1.5 tones of CO2. If KMLNG were assessed the tax given $30 / tonne of CO2 produced, the rate of production of 700 MMcf equals 14371 Metric tonnes LNG. If this figure is divided by 1/3, then the assessed value for Carbon that is created at KMLNG is 4790.3 Metric Tons of CO2 / day. When this is taxed at the rate of $30 / tonne then the tax that is generated would be an additional $143,710.00 / day at KMLNG. This would amount to $52,454,150 / year or approximately $1.05 Billion over the life of the project.

Project Costs are also considered with the CBA for KMLNG and need to be deducted for accounting purposes. *Land degradation* is one of the costs associated with KMLNG and the proposed developments have to be assessed as standing for the CBA.

As shown in Figure 19, 661 average wells per year have been constructed on multi-well pads from 2009 - 2011 in BC (OGC, 2012). As stated before, even at these drilling levels, the production of natural gas has gone up in recent years due to the increase in production due to horizontal drilling technologies.
In BC, average well sites have 6 wells drilled per pad site at an approximate average of 2 hectares per site (personal analysis, 2012). The current BC production of gas degrades 220 hectares of land/year with other developments such as roads and pipelines added to this figure. These disturbances are linear in nature and require clearing but in most cases are not classified as long term disturbance as most major infrastructure for roads is in place. Plans for the KMLNG site have not been completed as the Front-End Engineering and Design (FEED) is not completed; however, there are other mega-projects that would be comparable with the KMLNG site. The Cabin Gas plant is located in the far Northeast of BC and has a footprint of 100 hectares in size (BCOGC, 2012). This area would be a good surrogate for the footprint size of the liquefaction facility in Kitimat. The Pacific Trails Pipeline is also a sizable area that will be taken up for the KMLNG project. The total area for the cabin gas plant is 100
hectares and this will be the assumable footprint for KMLNG. As indicated, the Pacific
Trails pipeline will be 463 km long and will span from Summit Lake, BC to Kitimat
bringing natural gas to the facility. The area for his pipeline will be 50 meters in width
on average and will therefore take up 2315 hectares of land (OGC, 2012). The total
area of land degradation will be \((220 \times 20 \text{ years}) + 100 \text{ KMLNG} + 2315 \text{ hectares}\) for a
total land degradation total of 6815 hectares for the life of the project. If the production
capacity at the KMLNG facility is doubled, then the rate of well site construction is also
doubled and the total degradation is 11215 hectares. Anielski and Wilson (2005)
describe average market values of boreal natural capital and associated environmental
and societal costs in their evaluation of boreal areas in BC. They provide estimates of
the total market values associated with the extraction and development of the Boreal
region’s natural capital and provide assessments of the value for this land from a
development perspective. They suggest that the plug-in value for just Forestry and oil
and gas use is $83.63 in 2002 / hectare. This value at average inflation rates (2.5%) is
now valued at $107.05 / hectare; however, this value does not take into account the
overlapping values of the land that are a more true reflection of the value of the land.
The land in the Peace region supports farm use, recreation, camping, aesthetics and
other societal values unrelated to the isolated potential for industry. For this reason the
“value” of land that is permanently taken up for use in the production of natural gas is
much higher than Anielski and Wilson (2005) describe. When all other values are
considered, the value for this land will be assessed by the suggested value and adjusted
by a factor of 10. This will adequately represent different values across the gradient of
value for KMLNG. The value for the 6815 hectares of land with the first KMLNG scenario is $7,295,457.50 after consideration for multiple resource values.

**CO₂ creation** is a downstream effect and project cost that has standing and needs consideration with KMLNG. For the KMLNG project, the rate of production of 700 MMcf/day yields a total of 14371 Metric tons LNG as we have previously determined. As discussed in the carbon tax example above, this creates 4790.3 Metric Tons of CO₂/day with the first scenario in the CBA. This is a global effect that needs consideration as natural gas will be consumed by the end use customer has a global cost associated with it. Costs in creation of CO₂ are in the form of costs to the environment through inherent global warming processes and through the direct health costs that affect people through time (Burtraw et. al., 1998). Natural gas is often described as one of the cleanest fossil fuels, producing less carbon dioxide than either coal or oil (USEPA, 2012). However, the effects from burning natural gas are well known and analysts need to account for emissions associated with its production and consumption. In or to monetize such effects Matthews and Lave (2000) outline using approaches such as the damage function approach for evaluation of damages associated with pollutant emissions.

Another concern and potential social cost are the contributions to global carbon emissions through errant losses associated with production. In addition to the creation of greenhouse gasses at the time of combustion, it is estimated that there are approximately 20% losses of natural gas that is lost through to the customer from the point of extraction (OGC, 2012). The USEPA (2012) indicates that natural gas itself is a greenhouse gas and is more potent than carbon dioxide by volume. Although natural gas is released into the atmosphere in much smaller quantities than CO₂, methane is
oxidized in the atmosphere, and hence natural gas affects the atmosphere for approximately 12 years, compared to CO2, which is already oxidized, and has effect for 100 to 500 years (USEIA, 2012). Based on composition, a ton of methane in the atmosphere traps as much radiation as 20 tons of carbon dioxide; however, it remains in the atmosphere for 8–40 times less time (USEIA, 2012). Matthews and Lave (2000) investigate the social cost of air pollutants based on damage function studies conducted in the US. They look at the costs resulting from a one-ton increase in each pollutant and assign a monetary cost value to this emission that is borne to society. For the global warming potential they calculate that the global warming potential for one tone of CO2 emissions to have a shadow price value of $20 in 2008 dollars. In using the future value of money formula: $FV = PV (1 + i)^N$ and an inflation rate of 2.5% then the value of this pollution is $22.08 in Canadian dollars for 2012 considering US and Canadian money is currently at par. As determined previously, KMLNG creates 4790.3 Metric Tons of CO2 / day; when the cost of $22.08 / tone is multiplied, the total societal cost of $105,751.90 / day is assessed given the rate of production of 700 MMcf / day. This amounts to a total cost for KMLNG of $772 million for the length of the project. This amount has to be increased for the fugitive emissions that are also a cost of the production system. If 20% of the production is lost in production and transportation then there is an additional 140 MMcf of natural gas that is both raw and flared\textsuperscript{10} to the environment. This amounts to an additional 956.06 Metric Tons of CO2 / day that would be introduced given the current losses that are associated with natural gas production. Because part of the gas is “raw” and the environmental effects are greater for these

\textsuperscript{10} Flaring is a disposal method for combustible gases associated with petroleum and natural gas production, processing and transportation Source: OGC, 2012.
emissions, a plug-in value of $35 is more appropriate from Matthews and Lave (2000). The value for this value in 2012 Canadian dollars is $38.63 tone of emissions. This equates to an additional $36,932.60/day for the KMLNG. The total from both sources for the CBA of the project for all sources of resulting CO$_2$ in the operation of LMLNG for the 20 year period is $1.042 billion dollars.

**Water consumption** with the production of natural gas is a topic of much discussion and is very controversial. The process of hydraulic fracturing consumes a lot of water however Canada has vast amounts of water that are available to its use. According to the OGC (2012), typically between 2500 m$^3$ and 5000 m$^3$ of water is used per fracturing stage. With current well designs and today's technology, this can translate to volumes in the order of 60,000 m$^3$ or more per well, depending on the number of “fracs”. In the years 2009 until 2011, the average number of wells drilled in BC averaged 661/year (BCOGC, 2012). The reduction of the number of wells drilled has been as a result of unconventional drilling needing fewer wells drilled to produce even more gas. From this an average the amount of water consumed can be deduced to be 80% of the wells drilled using water stimulation at 530/year x 60,000 liters. This equates to approximately 31.8 million M$^3$ of water consumed to produce roughly BC’s annual production of 12 BCM natural gas per year. KMLNG will produce an equivalent of 7.2356 BCM per year or 60.3% of the production capacity of the province currently. With this ratio being equivalent, KMLNG will result in approximately 19.2 million M$^3$ of water consumed per year of operation. Fresh water in the global context is becoming scarcer through time and the value of potable water continues to grow. Paulo et. al. (2001) discuss the value of water and water quality in surveys associated with
biodiversity measures with aquatic ecosystems. This model monetizes the value of water in different habitat ranges by use. The units of value are expressed in their study as values per acre-foot whereby one acre foot equals 325,851 gallons or 1,233.5 M$^3$.

When the values are added up from the model, the average value for the shadow price values is $142.15. This value seems appropriate for the acre-foot loss to the system as many of the uses are applicable to the Peace region where the majority of all natural gas is produced in BC. With KMLNG, the total volume of 19.2 million M$^3$/1233.5 M$^3 = 15565.47$ acre / feet of water consumed per year. At a plug in value of $142.15 per acre / foot, this equates to $2,212,630.73 / year for water consumption per year to produce the gas required for KMLNG. Over the life of the project, this would amount to $44.25 Million in costs for the CBA.

**Habitat and species effects** for different species such as caribou are relatively unknown and many studies are being contemplated or undertaken to understand the effect of oil and gas developments on different species (OGC, 2012). Boreal Caribou are listed as threatened under the federal Species at Risk Act (SARA), are provincially red-listed (Threatened to Endangered) (BCMOE, 2012). Approximately 1300 Boreal caribou occupy 6 herds in areas of northeast British Columbia. This is of significance to the natural gas industry as there is much overlap with Boreal Caribou range. The populations of Boreal Caribou in British Columbia are contiguous with Boreal Caribou in Alberta and Northwest Territories as the herds of animals move across these jurisdictional boundaries (BCMOE, 2012). Boreal Caribou in British Columbia are believed to be in decline and this may be attributed to habitat loss, fragmentation and alteration of habitats from forestry and petroleum and natural gas activities. Nunes and
van den Bergh (2001) assess the effects and environmental impacts to all species from the degradation of habitats of different eco-type. Their assessment identifies and monetizes the values of various levels of biodiversity. As a large portion of the natural gas areas are in areas comparable to the studies that were undertaken in wilderness land in the US, these plug-in values will be appropriate for this study. The annual wetland value in the studies that were assessed by Nunes and van den Bergh (2001) indicate that these areas have a value of $3948.00 / hectare / year. Terrestrial ecotypes were assessed had lower value of $2271.96 / hectare / year. For KMLNG and the Pacific Trails Pipeline, the majority of areas the activity affects are not in wetlands; however, many of the areas that current natural gas developments occur on in Northeast BC are in areas of wetland habitat. As assessed earlier with degradation, the total area of land taken up for the KMLNG project will be (220 x 20 years) + 100 KMLNG site + 2315 hectares for a total land degradation totaling 6815 hectares for the life of the project. Furthermore, if production capacity at the KMLNG facility is doubled, then the rate of well site construction is also doubled and the total degradation is 11215 hectares. If we assume that half of the areas for natural gas developments are in areas that have wetland characteristics, then the values of the effects to the rate of biodiversity values can be calculated. Therefore, 2200 hectares is assessed $3948.00 / hectare / year = $8,685,600 for the life of the project. The Terrestrial value for 2200 hectares is assessed at $2271.96 / hectare / year = $4,998,312. The KMLNG site and associated Pipeline have an overall footprint of 2415 hectares multiplied by the terrestrial rate of $2271.96 / hectare / year = $5,486,783.4. This assessment is somewhat problematic as it

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11 A subdivision of an ecospecies consisting of a population that is adapted to a particular set of environmental conditions.
disregards the effects of time and the time value for development. Natural gas developments will be ongoing to produce the gas for the KMLNG plant on an ongoing basis so there will be a delay in the costs that will be incurred. The KMLNG project and pipeline will be constructed in year one of the project and will therefore incur social costs to biodiversity for a longer period of time relative to natural gas developments. These affects will be ignored and the assumption will be that these will normalize through time. The result of the environmental impacts from a biodiversity standpoint is a cost of $19.17 million as of 2006. In 2012 dollars this equates to $22.23 million for the KMLNG project for scenario A of the CBA. If the capacity of the plant were doubled, the resulting natural gas developments would result in an additional $3948.00/hectare/year = $8,685,600 AND $2271.96/hectare/year = $4,998,312 for an additional environmental impact cost of $13,683,912 for the project. In 2012 Canadian dollars this amounts to an additional $15,869,142.68. This would be the environmental impact cost with taking on scenario B in the CBA for KMLNG.

*Loss of use of the land* for purposes associated with the general use of the public is also a cost of the CBA assessment of KMLNG. Kaval and Loomis (2003) discuss the ways to monetize long term impacts using plug-in values in CBA. They suggest that the cost of a general recreation day is $38.96 in 2002 US dollars. They also postulate that values across all recreation activities to be $53.00. In the case of the areas that are taken up for the development and use in the KMLNG project, there are areas that are considered high and low for the potential of human recreation. There are also areas that are of very high value for both recreation and aesthetic values such as for the plant site and the Pacific Trails Pipeline corridor. For this CBA, the plug in values are
appreciated in current dollar values using the average value appreciated to today’s value using an inflation rate of 2.5%. $38.96 Canadian dollars inflated for a 10 year period to 2012 dollars is a plug in value of $49.87. It is assumed that 10 hectare area will support an activity day to the public as some of the areas are remote and vast and do not see human activities on a constant basis. In the 700 MMCF scenario, this equates to $12,405,037 of activity day value loss to the public ($49.87 x (6815/10) x 365 days) in the 1 year period. This value is then multiplied by the length of time of the project to result in a $248.1 million cost for the loss of use of the area for the duration of the project. The cost for the capacity of KMLNG to double also needs consideration for the CBA. In the 1.4 BCF scenario, the value of loss of use for cost per year of activity for KMLNG is $20,414,159. For the term of the project this equates to $408.3 million dollars.

The Future Value of natural gas has to be considered being that natural gas is a finite resource that will one day be exhausted. If we consider that the value of the gas will appreciate and be approximate that the gas will have value equal to or above the cost of inflation then we can assess a value to the future volume of gas from the system. The simple interest formula is as follows:

\[ FV = PV (1 + r^t) \]

Where:
- \( FV \) = future value
- \( PV \) = Present Value
- \( r \) = Interest Rate
- \( t \) = Time in years

If we assess the current value of North American gas to be $2.50 today on average and we assume that the interest rate of inflation to be approximately 3% then we have the
following solution for the future value of the gas that will be extracted over the time of the KMLNG project. Thus, the future value of KMLNG gas if left undeveloped would have a minimum value of:

\[ FV = \$2.50 \times (1.03^{20}) = \$4.51 \text{ MCF in 20 year's time} \]

KMLNG will produce 255500 MMcf/year = $1.152 billion worth of gas/year amounting to $23.04 billion dollars’ worth of Natural gas if left untouched until 2035. This amount is inherently flawed as we have seen that the values for natural gas in North America are at record low prices and therefore, using an average plug-in value based on projected value would have more realistic value.

### 7.2.4 Quantitative Impacts for KMLNG

For this step of the CBA, the analyst makes predictions for the life of the project based on the different parameters or options involved with the project(s). For KMLNG, the cost and benefit will change for the two production levels and the net social cost is compared with the net social gain. Different values for different variables that have standing are shown in Table 7 below. What is noticeable in this analysis is that the net social benefit for leaving the resource untouched is $23.04 billion versus the net social benefit of $46.61 billion of the life of the project with this analysis completed; we can make the recommendation to consider the project from a social perspective before we consider the social NPV. It is also recommended to undertake scenario B given these findings to maximize the total social benefit after deducting the total social costs for the total social benefits.
Table 8: Social Cost-Benefit Analysis for KMLNG considering all variables gross value at year 20.

<table>
<thead>
<tr>
<th>Social Cost-Benefit Analysis</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
</tr>
<tr>
<td></td>
</tr>
<tr>
<td>Project Benefits:</td>
</tr>
<tr>
<td>employment return</td>
</tr>
<tr>
<td>royalties</td>
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<tr>
<td>taxation</td>
</tr>
<tr>
<td>carbon tax</td>
</tr>
<tr>
<td>Total</td>
</tr>
<tr>
<td>Project Costs:</td>
</tr>
<tr>
<td>land PL + plant degradatio</td>
</tr>
<tr>
<td>CO2 creation</td>
</tr>
<tr>
<td>water consumption</td>
</tr>
<tr>
<td>habitat disruption</td>
</tr>
<tr>
<td>loss of use</td>
</tr>
<tr>
<td>Future Value</td>
</tr>
<tr>
<td>Total</td>
</tr>
<tr>
<td>Net Benefit Billions $</td>
</tr>
</tbody>
</table>

One of the challenges with scenario B is that it represents 120% of the current production amounts for the entire province meaning that BC would have to ramp up production significantly in order to meet production demand while maintaining its domestic gas supply.

Valuing the effects to the environment is difficult; however, values for different variables are available in environmental evaluation research. With this assessment, consumers’ willingness to pay has to be a consideration in order to assess the appropriate market demand for the good in question. Boardman et. al. suggests the use of plug-in values wherever possible to monetize the values of different variables that are considered standing in the system (2010). As we have completed the financial
assessments of the different costs and benefits and summarized them in Table 7 above, the monetization for these variables for KMLNG is completed.

7.2.5 Discounted benefits of KMLNG

In order to conduct CBA, benefits and costs are discounted to obtain their Present Values before the NPV is calculated. Table 7 above considers gross, cumulative values and does not discount these values accordingly. For projects that have impacts that occur over several years, we need a way to aggregate the benefits and the costs that occur in different years. In order to compute present values (PV) for both the benefits (B) and the costs (C) we need to calculate the social discount rate (S). The reason for future costs and benefits to be discounted is because there is an opportunity cost for resources used in the project (natural gas) and because there is social preference for individuals to consume now rather than later (Boardman et. al., 2010). In order to convert costs and benefits to future values the following equation must be used:

\[
PV(B) = B_t / (1+s)^t
\]

Where:
- \( PV \) = Present Value Benefit
- \( B_t \) = Benefit in \( t \) years
- \( S \) = Social Discount Rate

AND

\[
PV(C) = C_t / (1+s)^t
\]

Where:
- \( PV \) = Present Value Cost
- \( B_t \) = Benefit in \( t \) years
- \( S \) = Social Discount Rate
The objective for selecting the appropriate social discount rate is to make policy choices that maximize social welfare while undertaking projects that maximize the social benefits without needlessly taking on subsidy projects or taking unwarranted risks. The objective for this analysis are based on the premise that a project should be undertaken only if its discounted benefits exceed the opportunity costs of those resources, otherwise it should not. As we discussed in Chapter 6, from an industry perspective, the discount rate should be adjusted using the CAPM approach resulting in a discount rate of 15.74%. This rate is much higher than required as it reflects the discount rate from the industry perspective taking into account the risk of relative projects in this industry. This rate does not represent the social discount rate. Stern (2008) argues that it is not appropriate to use market rates for the assessment and calculation of social discount rates. He continues by explaining that for projects that affect or involve climate change, lower rates of discount are more appropriate. For KMLNG we will not use a social discount rate of 10% as recommended by government authorities in British Columbia as these are too high as they are based on market rates. For KMLNG, we will use the rate of 3.5% as indicated by Boardman (2010) and adjust this by the same risk factor that computed the risk factor for private investment. The result is a social discount rate ($S_o$) that represents the risk of the project from a social perspective at calculated below.

$$3.5\% \times 1.34 \beta = 4.69\% \ S_r$$

### 7.2.6 Social NPV of KMLNG

The social NPV of each alternative is defined as the difference between the present value (PV) B of benefits minus the present value (PV) C of costs. As we have
discussed, net present value is the discounted present value of a future cash flow of a stream (Ross et. al., 2007). The cost-benefit analysis involves understanding the economic, social, environmental, and other costs and benefits of investment and assessing the difference after discounting them. A cost-benefit analysis depends partly on finding the net present values of costs and benefits. Companies use these and other analytical methods to compare investment alternatives and evaluate the implications of business decisions. Table 7 below shows the Social NPV analysis with the discounted costs and benefits for KMLNG.

Table 9: Social NPV Analysis for KMLNG to year 7 of 20 in Billions $

<table>
<thead>
<tr>
<th>Social NPV Analysis</th>
</tr>
</thead>
<tbody>
<tr>
<td>---------------------</td>
</tr>
<tr>
<td>Project Benefits: Employment</td>
</tr>
<tr>
<td>Royalties</td>
</tr>
<tr>
<td>Taxation</td>
</tr>
<tr>
<td>Carbon tax</td>
</tr>
<tr>
<td>Total</td>
</tr>
<tr>
<td>NPV</td>
</tr>
<tr>
<td>Project Costs: Land PL + plant degradation</td>
</tr>
<tr>
<td>CO2 creation</td>
</tr>
<tr>
<td>Water consumption</td>
</tr>
<tr>
<td>Habitat disruption</td>
</tr>
<tr>
<td>Loss of use</td>
</tr>
<tr>
<td>Future Value</td>
</tr>
<tr>
<td>Total</td>
</tr>
<tr>
<td>NPV</td>
</tr>
<tr>
<td>Social Net Benefit $ Billions</td>
</tr>
</tbody>
</table>

In looking at this analysis, it is evident that the net social benefit after discounting is positive suggesting that there is a definite value from the social perspective.
7.2.7 Sensitivity analysis for CBA

There can be considerable uncertainty regarding certain impacts and the appropriate monetary valuation of each unit of impact using CBA. Boardman et. al. (2010) discusses the difficulties in predicting future values for monetizing costs and benefits when there is uncertainty involved. With CBA, assumptions of the analytical effort can be assessed using sensitivity analysis and the robustness of those assumptions surrounding the associated costs and benefits can be critically investigated. They continue by explaining that CBA is structured in terms of contingencies and their probabilities and that there is always uncertainty regarding the magnitude of the variance in the values that were determined and monetized. To deal with this uncertainty, sensitivity analysis can be used with CBA to investigate the results of changes in assumptions. This does not predict the changes from a substantive market disruption, but rather, gives some increased confidence in the findings from the CBA should some unforeseen changes exist. For the prediction of natural gas by the EIA (2011) shown in figure 15, the price of oil in 2035 is graphed for the high, reference and low oil price that is expected. When we consider these values of $200, $125, and $50 / barrel, this presents a large risk to the KMLNG project because of the current ways that LNG is priced using the Japanese Crude Cocktail. If we consider the Standard Deviation (SD) of these values where STDEV.S uses the following formula:

$$\sqrt{\frac{\sum(x-\bar{x})^2}{n-1}}$$

Where x is the sample mean AVERAGE (number 1, number 2, ...) and n is the sample size. The SD for the future oil price using the EIA oil projections from figure 15 is 75 with an average value of $125 / barrel. This represents a high amount of
variability for the key indicator for the success of the project from an industry perspective. Boardman et. al. (2010) discusses the different options for completing a sensitivity analysis with CBA. If the analysis considers the volatility of different variables such as the SD such as the price of oil in the future, the net benefits and costs can be adjusted to represent a change in a given variable. This is discussed as a partial sensitivity analysis which allows the isolation and assessment of a given variable in the analysis. If we consider the variability (SD = 75) as a percentage of the mean value of $125/ barrel for oil in 2035 this value is 60% of that mean. The social discount rate can then be adjusted by up to 60% to isolate the risk in the pricing of LNG from a social perspective. The result is a social discount rate (S_r) that represents the risk of the project from a social perspective with the risk of the variability for the price of oil (= price of Asian LNG) at calculated below.

$$3.5\% \times 1.34 \text{ beta} = 4.69\% \quad S_r \times 1.6 = 7.504\%$$

When the risk of variance in the price of oil in the future is considered, the results to the social NPV is shown in Table 9 below:
Table 10: Social NPV Analysis with Risk of Oil Price Variance for KMLNG to year 7 of 20 in Billions $

<table>
<thead>
<tr>
<th></th>
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<td></td>
<td></td>
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</tr>
<tr>
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<td>1.015</td>
<td>1.015</td>
<td>1.015</td>
<td>1.015</td>
<td>1.015</td>
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<td>0.3065</td>
<td>0.3065</td>
<td>0.3065</td>
<td>0.3065</td>
<td>0.3065</td>
<td>0.3065</td>
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<tr>
<td>taxation</td>
<td>0</td>
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<td>0.02515</td>
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<td>0.02417</td>
<td>0.02366</td>
<td>0.02316</td>
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<tr>
<td>carbon tax</td>
<td>0</td>
<td>0.0525</td>
<td>0.0525</td>
<td>0.0525</td>
<td>0.0525</td>
<td>0.0525</td>
<td>0.0525</td>
</tr>
<tr>
<td>Total</td>
<td>0</td>
<td>1.39963</td>
<td>1.39915</td>
<td>1.39866</td>
<td>1.39817</td>
<td>1.39766</td>
<td>1.40416</td>
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<tr>
<td>NPV</td>
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<td>$13.00</td>
<td></td>
<td></td>
<td></td>
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</tr>
<tr>
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<td></td>
<td></td>
<td></td>
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<td></td>
<td></td>
</tr>
<tr>
<td>land PL + plant degradation</td>
<td>0.0073</td>
<td>0</td>
<td>0</td>
<td>0</td>
<td>0</td>
<td>0</td>
<td>0</td>
</tr>
<tr>
<td>CO2 creation</td>
<td>0</td>
<td>0.0521</td>
<td>0.0521</td>
<td>0.0521</td>
<td>0.0521</td>
<td>0.0521</td>
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<tr>
<td>water consumption</td>
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<td>0.00221</td>
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<tr>
<td>habitat disruption</td>
<td>0</td>
<td>0.00111</td>
<td>0.00111</td>
<td>0.00111</td>
<td>0.00111</td>
<td>0.00111</td>
<td>0.00111</td>
</tr>
<tr>
<td>loss of use</td>
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<td>0.012405</td>
<td>0.012405</td>
<td>0.012405</td>
<td>0.012405</td>
<td>0.012405</td>
<td>0.012405</td>
</tr>
<tr>
<td>Future Value</td>
<td>0</td>
<td>1.152</td>
<td>1.152</td>
<td>1.152</td>
<td>1.152</td>
<td>1.152</td>
<td>1.152</td>
</tr>
<tr>
<td>Total</td>
<td>0.0073</td>
<td>1.219825</td>
<td>1.219825</td>
<td>1.219825</td>
<td>1.219825</td>
<td>1.219825</td>
<td>1.219825</td>
</tr>
<tr>
<td>NPV</td>
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<td>$11.30</td>
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</table>

This shows that the KMLNG project remains viable with a net social benefit of $1.70 billion from a societal perspective with the risk in the value of crude oil in the future being considered. This partial sensitivity analysis isolates the most variable aspect in the analysis and adjusts the risk factor for the social discount rate accordingly.

7.2.8 CBA Recommendation

When the social and the industry cost-benefits are considered for the KMLNG project, both yield an overall benefit for both parties. When the NPV of the different analysis is considered, the net benefit is much lower from a social perspective that an industry one. The net NPV value for both industry and for society, when considering the discounted cost-benefit is $1.7 billion and $1.69 billion, indicating respectable margins for both industry and society for the KMLNG project. It is recommended
based on the findings of the project for society and industry to proceed with the
KMLNG project to capture market share with the disruption in the natural gas sector in
North America.
Chapter 8

CONCLUSION AND RECOMMENDATIONS

Technological advances have resulted in lower North American natural gas prices for all involved with the increase in natural gas available. This market disruption has resulted in many companies in Canada and the US looking for different alternatives for their natural gas. British Columbia should seriously consider expansion into the world LNG market as a strategy to eliminate its dependence on a shrinking US natural gas market. Investments into the LNG market and subsequent natural gas development spending should be a top priority for British Columbia natural gas producers. Breaking into the global LNG market will not be an easy task as there is much competition from low-cost producers of LNG such as from countries like Australia and Qatar. Other companies other than KMLNG limited partnership are also looking at the potential LNG market accessed out of Canada’s west coast and there are negotiations occurring with many countries in the Pacific Rim to look at the potential to supply LNG for many years into the future.

BC royalty rate structures currently are designed for the North American market and may not reflect the actual value of natural gas on the global market. BC’s 2010 royalties that were collected by government were reduced by 460 million for subsidies that were designed to generate industry investment in the oil and gas industry (Government of British Columbia, 2010). As previously indicated, total royalties that were collected in BC for 2010 were 1.66 billion suggesting that with different economic conditions (as a result of higher demand due to LNG) there may be no need for royalty
subsidiies. However, these programs have allowed BC to stimulate oil and gas activities even through the global recession, and there should be a resistance to the immediate discontinuation of these programs. Charging a LNG premium for Alberta and US gas flow through Kitimat may not be required as there may be opportunities to charge a carbon tax on LNG that is produced in BC. The BC government should carefully assess the outcomes of the KMLNG supply deals should they materialize, and not act prematurely to adjust natural gas royalty rates until the full financial viability of the project(s) are known. In considering the NPV values from an industry perspective in table 6 and 7, the BC government should initiate royalty changes only after the true, long-term value of BC’s LNG is known. Should BC make changes prematurely, companies may elect to take their investment dollars out of BC and invest where their costs are lower from a taxation perspective.

Future work in assessing Kitimat LNG should assess the global financial market relative to interest arbitrage and interest rate parity and this should be well understood by companies involved in negotiating long-term LNG deals. Terms of the supply agreement(s) are the most critical aspect of making KMLNG a viable project and there are several options that the company needs to consider when maximizing their chance of success. These priorities in order of importance are to:

1. Negotiate rates of compensation based on future values of currencies with consideration towards trends in inflation and current costs of natural gas production.

2. Consideration towards the fixed costs for production on an ongoing basis. The investment decision should carefully entertain increasing the initial investment and
including the best technologies available to decrease the costs of labour and energy consumption for conversion of natural gas to LNG.

3. Cost over-runs have lower but substantial effects to the viability of the project. LNG facilities involve large investments in capital and this need not be exacerbated through costing that was not initially accounted for.

4. Understanding that production delays will yield the lowest effect on the productivity of the project however these delays are the simplest to avoid. Employing the right project management team can reduce delays in becoming fully operational and can make needless late orders avoidable.

KMLNG has the option to double their planned output for the project under their export permit. The financial analysis, should KMLNG double its capacity, is greatly improved giving margins that are much better than the base case in this assessment. It is highly recommended that the KMLNG limited partnership consider options that maximize capacity in order to reap the benefits of efficiency of scale. BC should encourage utilization of its natural gas resources to LNG so that the market for BC natural resource is maintained into the future. The BC government should consider keeping royalty programs in place until BC natural gas has access to the LNG marketplace to stimulate these investments. This will ensure demand for BC natural gas continues into the future. Increased revenues from the sale and conversion of LNG could be captured by the BC government through the Carbon Tax system that is already in place allowing Alberta and US produced natural gas to be taxed when it is converted to LNG in Kitimat. In any case, the KMLNG project offers a positive social and
industry net benefit given the elements of the cost-benefit analysis and should be considered in the final investment decision to proceed with the project.
Appendices

Appendix 1 – Conversions for KMLNG Production Volumes

KMLNG Conversions Scenario A

700 MMcf / day = million cubic feet / day
255500 MMcf/year
5245415 Metric tone (t) LNG / year
5.25 Million tones LNG / year

KMLNG Conversions Scenario B

1400 MMcf / day = million cubic feet / day
511000 MMcf/year
10490830 Metric tone (t) LNG / year
10.5 Million tones LNG / year

Appendix 2 – Conversion Factor Table – Source: EIA

<table>
<thead>
<tr>
<th>Natural Gas &amp; LNG</th>
<th>billion cubic meters NG</th>
<th>billion cubic feet NG</th>
<th>million tones oil equivalent</th>
<th>million tonnes LNG</th>
<th>trillion British thermal units</th>
<th>million barrels oil equivalent</th>
</tr>
</thead>
<tbody>
<tr>
<td>From</td>
<td>Multiply By</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>1 billion cubic meters NG</td>
<td>1</td>
<td>35.3</td>
<td>0.9</td>
<td>0.72</td>
<td>36</td>
<td>6.29</td>
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<tr>
<td>1 billion cubic feet NG</td>
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<td>0.026</td>
<td>0.021</td>
<td>1.03</td>
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<td>1 million tonnes oil equivalent</td>
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<td>39.2</td>
<td>1</td>
<td>0.805</td>
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<td>1 million tonnes LNG</td>
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<td>1 trillion British thermal units</td>
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<td>0.025</td>
<td>0.02</td>
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<td>1 million barrels oil equivalent</td>
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<td>Peru</td>
<td>Belgium</td>
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<tr>
<td>North America</td>
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<tr>
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<td>0.36</td>
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<td>S. &amp; Central America</td>
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<td>0.85</td>
<td>0.15</td>
<td>0.08</td>
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<td>3.97</td>
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Bibliography


List of Figures

Figure 1: US price expectation with predictions.................................4
Figure 2: Kitimat would be the closest export facility once constructed........10
Figure 3: Representation of the Kitimat LNG Plant once constructed........11
Figure 4: Proposed route of the Pacific Trails Pipeline........................12
Figure 5: Current Shale Plays in North America.................................14
Figure 6: Natural Gas Exported from British Columbia to the US - 2001 – 2010.....15
Figure 7: US consumption over the past 10 years 2001 – 2010........................16
Figure 8: Relative amounts of natural gas exported to the US by province in 2010.....17
Figure 9: Henry Hub price for natural gas Jan. 2010 to Jan. 2012..................18
Figure 10: Historical usage of natural gas in the United States...................19
Figure 11: US production over the past 10 years 2001 – 2010......................21
Figure 12: World LNG market import values by region as of 2010..................22
Figure 13: Japan LNG Market Values / Mbtu in USD.............................23
Figure 14: Asian LNG Market Import Values BCM in 2010.........................24
Figure 15: Projected price of oil 2011 to 2035..................................32
Figure 16: Royalties per thousand cubic feet of Marketable Natural Gas Production in BC and Alberta.................................44
Figure 17: Different prices given different demand................................46
Figure 18: Risk free rate in Canada since 2002.....................................50
Figure 19: Wells drilled in BC 2001 – 2011........................................60