A Techno-economic Assessment of the Liquefied Natural Gas (LNG) Production Facilities in Western Canada

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Research Highlights

- A data-intensive techno-economic model based on the engineering parameters was developed to assess the production cost of LNG in western Canada.
- Cost correlations linking the equipment's design parameters to the installed cost of the equipment were developed and described.
- The cost to deliver Canadian LNG to Asian countries (Japan, China, and India) was estimated.
- A sensitivity analysis was conducted to identify the key variables impacting the total liquefaction cost.

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Abstract

The availability and low cost of natural gas in North America open the possibility of transporting it to places where there is significant demand. Natural gas can be transported long distances as liquefied natural gas (LNG). In this paper, data-intensive techno-economic models were developed to assess LNG production costs in western Canada. A two-train (each with an annual natural gas liquefaction capacity of 5 million tons) LNG plant is designed in the context of anticipated LNG export facilities in British Columbia, Canada. The plant equipment parameters and costs were estimated using a data-intensive bottom-up cost calculation methodology. Cost correlations linking the equipment's design parameters to the equipment's installed cost were developed and overall costs assessed. The total installed cost of the plant equipment is about US$1.9 billion. Considering a $1200/tpa capital expenditure, a 12% discount rate, and a 25-year plant life, the total product (LNG) cost is $7.8/GJ, if the gas supply source is Montney, and $9.1/GJ, if the gas supply source is Horn River. The delivery cost of Canadian LNG to Asia was estimated and a sensitivity analysis conducted. Total liquefaction cost is influenced most by the LNG facility capital expenditure, gas supply cost, and the discount rate.

Keywords: Natural gas; liquefied natural gas; natural gas processing; liquefaction.

Nomenclature

C_{AT}	Cost of the absorber tower, $
C_b	Cost coefficient in cost of absorber tower, which depends on weight of absorber column

W_a	Weight of the absorber column, kg
V_p	Packing volume of the absorber tower, m^3
D_a	Diameter of the absorber, m
L_a	Length of the absorber, m
C_R	Cost of regenerator column, \$
C_{HE}	Cost of heat exchanger in gas sweetening unit, \$
A_{HE}	Area of heat exchanger in gas sweetening unit, m^2
$C_{condenser}$	Cost of condensers, \$
$C_{Reboiler}$	Cost of reboiler in gas sweetening unit, \$
C_{AD}	Cost of adsorber column, \$
W_d	Weight of the desiccant, kg
C_D	Cost of deethanizer column, \$
D_d	Diameter of the deethanizer column, m
L_d	Length of the deethanizer column, m
C_C	Cost of compressors, \$
P_c	Power rating of the compressor, MW
C_{GT}	Cost of gas turbines, \$
C_T	Total liquefaction cost, \$
C_I	Total investment cost, \$
C_{IA}	Total amortized investment cost, \$
C_{OA}	Total amortized operations and maintenance cost, \$

C_{on}	Total on-site cost of the project, \$
C_r	Raw material cost, \$
C_U	Utility cost, \$
C_{labor}	Total operations labor cost, \$
r	Rate of return of the project, %
n	Lifetime of the project, years
L_c	Liquefaction capacity of the LNG plant, million tonnes per annum
$C_{LNG\ Plant}$	Total LNG plant cost, \$
gpm	gallon per minute
Tcf	Trillion cubic feet
Bcf	Billion cubic feet
Tcf/d	Trillion cubic feet per day
Bcf/d	Billion cubic feet per day

Acronyms

USD	United States dollar
LNG	Liquefied natural gas
NG	Natural gas
NGL	Natural gas liquid
BC	British Columbia
APCI	Air Products and Chemicals, Incorporation
C3MR	Propane pre-cooled mixed refrigerant

1. Introduction

The emergence of advanced fracturing and well drilling technologies coupled with the development of unconventional natural gas resources in Western Canada have opened up new opportunities and redefined the Canadian natural gas market. Recent estimates show that there are potentially 632 trillion cubic feet (tcf) of natural gas in the Western Canadian Sedimentary Basin, which is equivalent to 145 years of Canada's 2012 consumption of 3 tcf [1]. The emergence of advanced fracturing and well drilling technologies coupled with the development of unconventional natural gas resources have created export opportunities for natural gas producers in Canada, especially when the anticipated Canadian production exceeds the domestic consumption requirement.

Currently the U.S. is Canada's only natural gas export client and due to the development of unconventional sources of natural gas in U.S., Canada's net export of natural gas to U.S. is declining [2]. The net pipeline imports of natural gas from Canada to the U.S. have declined to around 158 billion cubic feet (bcf) in 2014 from 289 bcf in 2000 [3]. This decline has left Canada with LNG as the only other gas export alternative.

The Asia-Pacific region is a lucrative market for Canadian LNG producers for several reasons. First, natural gas prices in Canada are substantially lower than the Asia-Pacific region. Average wellhead/city gate prices of natural gas in British Columbia, Canada, are around \$4.7 per gigajoule [4], which is lower than Asian prices (\$15-16 per gigajoule) [5]. This price differential creates opportunities for profit for Canadian natural gas companies investing in developing LNG facilities. Second, Asia's regional share of global demand for natural gas has increased from 13 to 19% and overall consumption has nearly doubled in the past decade [3] [6], making the Asia-Pacific region the most significant region in international LNG trade. At the same time, the gap between demand and supply of natural gas is increasing due to the lack of sufficient hydrocarbon reserves, thereby increasing Asia's reliance on LNG and pipeline imports [7]. These developments, coupled with relatively high growth in electricity consumption and declining domestic fossil fuel energy, have made the Asia-Pacific region highly dependent on LNG imports to satisfy their energy requirements in near future [7].

Japan is the world's largest importer of liquefied natural gas [6] and its import volume is expected to increase from 3.18 trillion cubic feet (tcf) in 2009 to 4.0 tcf by 2035 [3]. The 2011 Fukushima nuclear power disaster, contributed somewhat to this increase. In order to achieve a reliable supply of LNG and to gain better control of LNG prices, policy makers in Japan are intent on diversification of sources of LNG [6]. Australia, Russia, Malaysia, and Qatar are the main LNG suppliers to Japan [6] [8]. For its LNG supply, China has largely relied on Australia since it began importing LNG in 2006. Australia contributed to around 80% of China's LNG import between 2006 and 2008 [6]. Similar to Japan, China has also focused on diversification of its LNG suppliers and imported around 10% of its LNG from each of Malaysia, Qatar, and Indonesia in 2010 [6].

As a result of this diversification, Australia's share in China's LNG imports dropped to less than 25% in 2012 [3]. Despite this drop, Australia is still China's largest source of imported LNG. In May 2014, Russia and China announced a new gas pipeline deal that would include shipments of 1.3 trillion cubic feet of gas to China over 30 years [9]. India's natural gas import scenario is comparable. Since 2004, India has seen an annual growth of 36% in its LNG imports and the Indian government is focusing on diversification and, to that end, signed deals with the U.S. and Australia in 2011 and 2009, respectively [3].

With an export capacity of around 77 million tons per year, Qatar is the world's largest producer and supplier of global LNG [9] and meets around one-third of global demand [10]. Australia ranks second in the list of LNG suppliers, but exports of LNG are expected to grow substantially in the coming years [9]. This is mainly because Australia currently has a large number of LNG export projects under construction [11]. Algeria, Malaysia, and Indonesia are Australia's strong competitors [8]. As discussed above, since all the three major Asian countries wish to diversity their LNG imports, Canada has a potential export market for its processed natural gas. Given that Asia's overall consumption of natural gas is expected to increase [12] and that Canada's natural gas prices will likely stay at their current level, there is good potential for Canadian natural gas producers. Moreover, political stability within Canada leading to a reliable supply of LNG can help Asian countries to build long-term LNG export contracts with Canada. Currently, most of the proposed liquefaction projects in Western Canada are undergoing a detailed study of construction costs to check the feasibility of the entire project. The unavailability of these studies in the public domain suggests an immediate need to conduct a detailed techno-economic study focusing on the cost estimates of Canadian liquefaction projects. However, as of now, there are no studies that focus on overall natural gas liquefaction costs in Canada. Most of the studies on natural gas liquefaction projects in literature pertaining to geographical regions other than Canada. Javanmardi et al. [13] estimated the total cost of natural gas liquefaction and shipping of LNG from the South-Pars gas fields in Iran to the world market. Other studies focus on the techo-economic analysis of different processes like gas-sweetening, dehydration, and natural gas liquid (NGL) recovery in an LNG plant. Lars Peters et al. [14] did a detailed technical and economic analysis of gas sweetening processes for natural gas with amine absorption and membrane technology. In this study, a simulation analysis with Aspen HYSYS for amine absorption and a membrane model interfaced within Aspen HYSYS was performed for different feed gas cases. Further, an economic analysis was conducted to evaluate gas processing costs and the total capital investment cost. Getua et al. [15] investigated the different process schemes used for known NGL recovery methods under variations of feed compositions with respect to their economic performance. Netusil et al. [16] compared the costs of three different natural gas dehydration processes that are widely used in the natural gas industry. The comparisons were made based on the process's energy demand and suitability for use. To address these gaps in academic literature and present a novel contribution, in this paper, a detailed economic analysis of the various process equipment used in an LNG plant with an annual liquefaction capacity of 10 million tonnes (the average capacity of the newly proposed LNG plants in British Columbia, Canada [see Appendix 2]), was carried out.

The overall objective of this paper is to conduct a comprehensive techno-economic study of the LNG production through development of techno-economic models. This was done by calculating the installation cost of different unit process equipment and estimating the entire cost of the plant. In addition, the overall cost from liquefaction to the final sale of LNG was calculated.

2. Methodology

2.1. System boundary description and cost estimation approach

The raw gas feed is delivered to an LNG plant in Kitimat, British Columbia, from the Horn River Basin or the Montney Play. The Horn River Basin, an unconventional shale gas play, represents around 28% of the remaining recoverable raw natural gas reserves in British Columbia, while Montney Play, an unconventional tight gas play represents 33% [17]. The different shale reserves and Kitimat Port are shown in Figure 1 below. An upstream LNG supply chain (see Figure 2) typically consists of four processes: production, transportation, gas processing, and liquefaction. In this paper, for each upstream process (other than production), a cost and scale analysis in the context of the anticipated LNG export facilities in British Columbia, Canada were conducted.

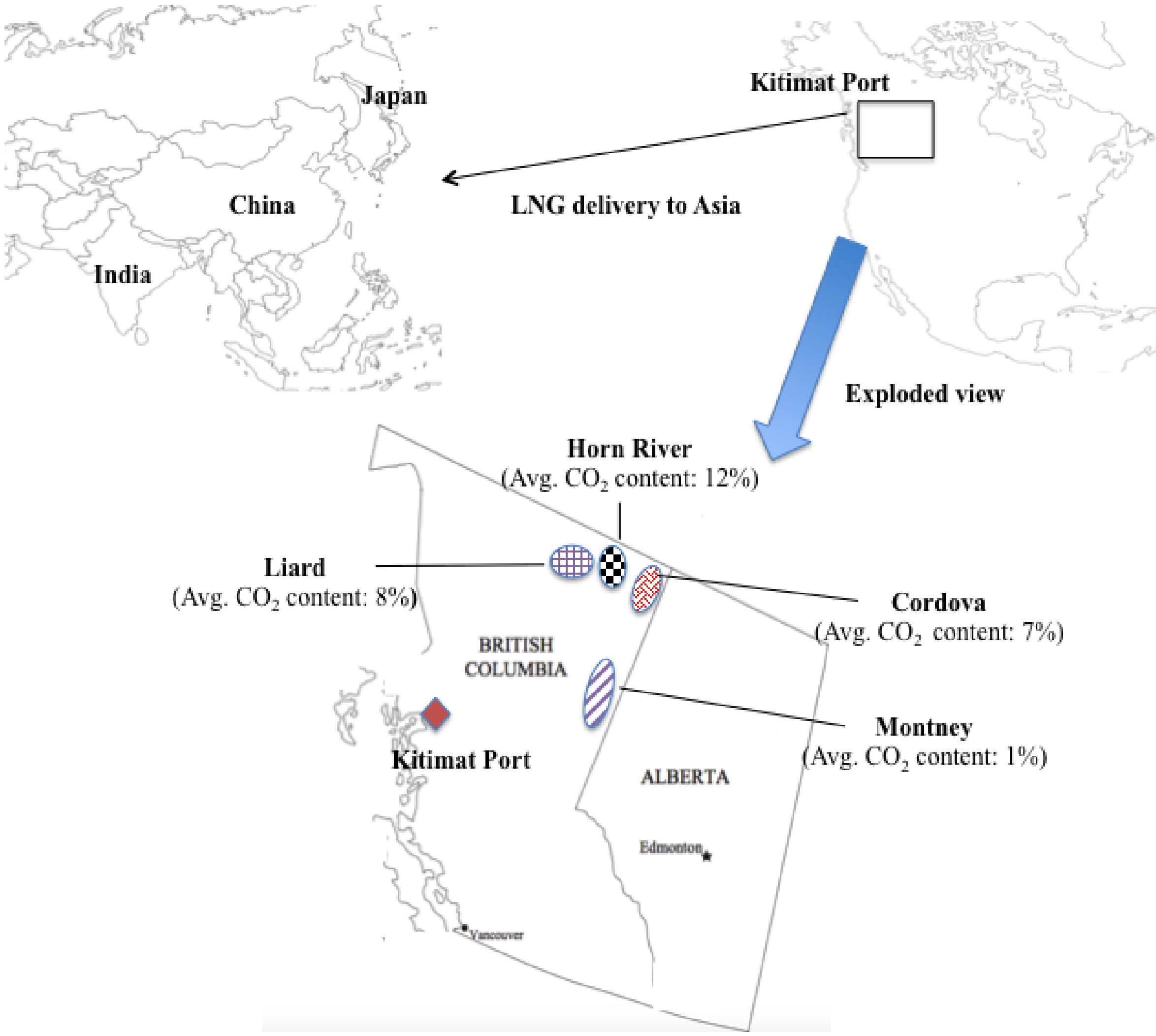

Figure 1: Map overview of Port Kitimat and different shale reserves in Western Canada

At the liquefaction facility, the gas undergoes processes such as gas sweetening, dehydration, natural gas liquid recovery, and liquefaction (see Figure 3).

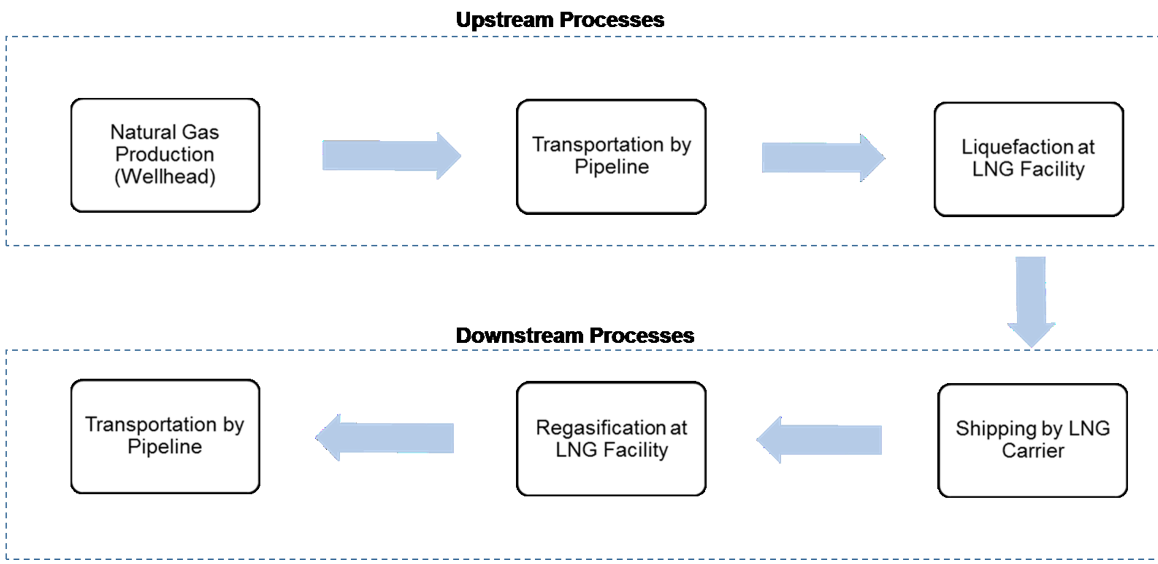

Figure 2: A typical LNG supply chain

The annual capacity of 10 million tons per annum (MTPA) corresponds to 39 million cubic metres per day of LNG production. Each process or unit operation illustrated in Figure 3 was analysed in terms of investment cost and operations cost. To calculate the equipment installation cost, of equipment a data-intensive model was developed considering bottom-up cost calculation methodology.

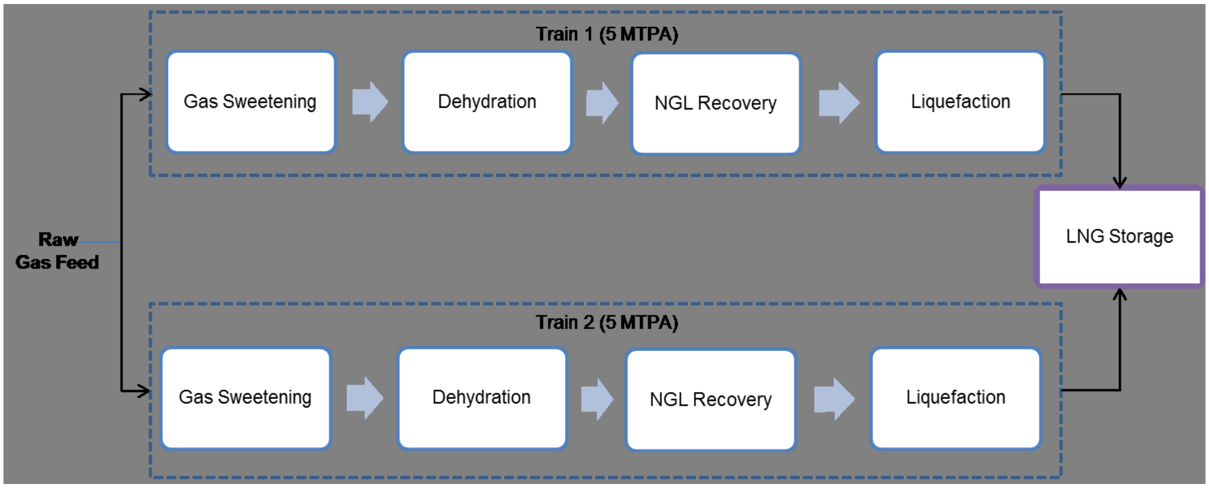

Figure 3: Major unit operations involved in a typical LNG facility

First, all major unit processes such as gas sweetening, dehydration, and NGL recovery are identified. Second, relevant equipment and the characteristics in each unit process are analysed.. This equipment is studied and analyzed based on parameters such as diameter, length, density, etc. These parameters correspond to a liquefaction capacity of 10 MTPA. Empirical relationships linking the equipment's parameters to equipment cost are developed. After determining the parameters, a bottom-up cost estimation approach is used. The equipment costs were considered to get the final installation cost or investment cost of a 10 MTPA LNG plant. Operations and maintenance costs are considered to estimate the total investment cost and subsequently the final total cost. A discounted cash flow analysis is conducted to calculate the cost of liquefying one gigajoule of natural gas. All the costs mentioned in the paper are in U.S. dollars with 2014 as the base year unless specified otherwise.

2.2. System description, data, and assumptions

2.2.1. Natural gas sweetening unit

To remove the acid gases (mainly hydrogen sulfide and carbon dioxide), raw gas is sweetened. This process helps prevent pipeline corrosion during gas transportation and reduces the volume of undesired gases [18]. In the gas sweetening unit, the feed gas is treated with aqueous amine solutions (diethanolamine [DEA] in this paper). DEA is considered because it leads to fewer hydrocarbon losses in the natural gas [10].

The absorber tower, lean/rich heat exchangers, stripper or regeneration column, condensers, and pressure vessels are the equipment that contribute most to cost in the acid gas removal unit [14]. The installation cost for this equipment is calculated using the methodology presented in section 2.1. Since the train size (5 MTPA) is large, the feed rate is high and hence two gas sweetening units in each train are considered, for a total of four. The feed rate of each acid removal unit is 359 mmscfd, which has been calculated based on the annual liquefaction capacity of the LNG plant. Note that the gas sweetening process is required only for gas produced from the Horn River basin. This is because the average CO_2 content in the recoverable gas from the Horn river basin is about 10%, and for the Montney formation this value is negligible [17]. To calculate the parameters of some of the gas processing equipment, GCAP [19] was used. GCAP, or Gas Conditioning and Processing, is a software package based on equations and correlations provided by John M. Campbell & Co. Javanmardi et al. [13] used this software package to estimate the design parameters of dehydration units in their research paper in which they estimate the total product cost of exporting LNG from the South Pars gas fields in Iran to world markets. The various parameters of the equipment used in a gas-sweetening unit are reported in Table 1.

Table 1: Parameters of equipment in a gas-sweetening unit

Parameter	Value	Unit	Source/Comment
Absorber tower			
• Gas flow rate	359	mmscfd	Calculated for a 10 MMTPA liquefaction plant
• Feed gas pressure	30-40	MPa	[17]
• Feed gas temperature	60-75	°C	[17]
• Average gas compressibility	0.96	-	[20]
• Gas relative density	0.59	-	[20]
• Value of coefficient (Ks)	0.03	m	[21]
• Material of construction (stainless steel 304) density	8000	kg/m^3	[22]
• Packing material used	metal		[23]

	ring, 2 inch		
• Diameter	4.02	m	Calculated using GCAP [19]
• Height (tangent-to-tangent)	8.14	m	Calculated using GCAP [19]
• Thickness	0.01	m	Calculated using GCAP [19]
Regenerator column			
• Column height (tangent-to-tangent)	22.34	m	Calculated using GCAP [19]
• Column diameter	4	m	Calculated using GCAP [19]
• Tray spacing	0.42	m	Diameter of the column lies in the range of 3.6m-7.3m [24]
• Number of trays	25		Calculated using column height and tray spacing values
• Material of construction (stainless steel 304) density	8000	kg/m^3	Generally used for petrochemical industry applications [22]

● Thickness	0.01	m	Calculated using GCAP [19]
● Total weight of the column	49,93 4	kg	Calculated using the pacing volume of the tower and density
Lean-rich amine heat exchanger			
● DEA circulation rate	52	gpm	Calculated for a feed rate of 359 mmscfd, k (DEA) of 1.45 [25] and acid gas mole percent of natural gas from the Horn River basin [17]
● Heating load	9.67	W	[21]
● Overall heat transfer coefficient	750	$W/m^{2\circ}C$	[13]
● Material of construction (stainless steel 304) density	8000	kg/m^3	Generally used for petrochemical industry applications [22]. This grade of steel has been used for both shell and tube construction.
● Area	849.3	m^2	Calculated using GCAP [19]
Condenser			

● Condenser cooling load	2.18	W	Optimal operating conditions [13]
● Condenser surface area	39.5	m^2	Calculated using GCAP [19]

In this paper, the equipment purchase price was calculated using the cost correlations given in Couper et al. [23] and Douglas [11]. The installation cost was obtained by multiplying the purchase price by the installation factor of the process equipment as provided by Gran [26], and the installation costs were updated using the 2014 Chemical Engineering Plant Cost Index [27]. The installation costs were then added in order to calculate the on-site costs. The purchase price of the absorption tower and regeneration tower were estimated using the values of the parameters (from Table 1) in cost correlations presented by Couper et al. [23] (see Equations 1, 2, and 3 in the Appendix). For the heat exchanger, the cost correlation, as shown in Equation 4, was obtained by calculating the cost of the lean amine heat exchanger for different surface area values using Matches' [28] equipment cost data for different types of heat exchangers and surface areas and then developing a general cost expression dependent only on surface area. However, this generalized equation is only valid for shell and tube heat exchangers constructed with stainless steel type 304 and pressure as described in Table 1. Using a cost estimation methodology similar to the one used to estimate the cost of lean amine heat exchanger as described above, the installed cost of the condenser, pressure vessels, and re-boiler was estimated. An additional 6% of the total installation cost was included as miscellaneous cost [24]. Since there are four gas sweetening units in the LNG plant (two units in each train), the total installation cost of the gas sweetening equipment is estimated by multiplying the gas sweetening per unit cost by four.

2.2.2. Dehydration unit

In this unit, water from the feed gas is removed by adsorption by a solid desiccant such activated alumina, silica gel, or molecular sieves [29]. The removal of water prevents the formation of hydrates in the main cryogenic heat exchanger during the liquefaction process. In this paper, adsorption by molecular sieve was considered because the sieve is considered the most versatile adsorbent and is capable of dehydration to less than 0.1 ppm water content [16] [29]. In order to carry out the dehydration process effectively, a minimum of two bed systems is required. Adsorption dehydration columns work alternately. This means that while one absorption bed is regenerated while the other dehydrates the wet gas. The regeneration is performed by preheated gas, which flows through the adsorbent into a cooler and then into the separator. In this paper it is assumed that the heater an ordinary burner. Since each of the LNG trains designed in this paper has a liquefaction capacity of 5 MTPA, the feed rate is very high (143 mmscfd). Therefore, to satisfy this requirement, 5 parallel dehydration units are used in each train with each dehydration unit consisting of 4 towers. The parameters for the adsorbers in the dehydration unit are presented in Table 2. Using the parameters developed for the adsorber tower (see Table 2) in Equation 7, we obtained the cost of an adsorber tower.

Table 2: Parameters for adsorbers in the dehydration unit

Parameter	Value	Units	Reference/Comment
• Gas flow rate	143.4	mmscfd	Calculated for a liquefaction capacity of 5 MTPA
• Gas pressure	6.78	Mpa	[13]
• Inlet gas temperature	311	K	[13]
• Inlet gas water content	0.0012	mole fraction	[30]
• Gas relative density	0.6	-	[20]
• Adsorption time	8	Hours	[29]
• Gas compressibility factor	0.96	-	[20]
• Number of towers in the plant	4	-	[9]
• Gas viscosity	0.012		[31]
• Useful desiccant capacity (weight %)	25	weight %	[16]
• Dynamic capacity at	20	weight %	[16]

saturation			
● Minimum required bed length	1.6	m	Calculated using GCAP [19]
● Minimum required bed diameter	1.75	m	Calculated using GCAP [19]
● Minimum required desiccant	2669.4	kg	Calculated using GCAP [19]

2.2.3. Natural gas liquid (NGL) recovery unit

In this process, the heavier hydrocarbons (C_3 - C_7 $^+$) present in the natural gas are absorbed preferentially by absorber oil in the absorption column. The hydrocarbon rich absorber oil leaves from the bottom of the absorption column and is expanded to liberate most of the absorbed methane. Afterwards, this rich oil is sent to a deethanizer column, where absorbed methane is rejected and part of ethane is absorbed. When the rich oil leaves the deethanizer column, it is sent to a regeneration column, where the higher hydrocarbons and other NGL components are driven to the top of the regeneration column by heating them to a very high temperature [32]. In this process major cost driving equipment are the deethanizer column, heat exchangers, pumps, compressors, and vessels [14]. For heat exchangers considered in this process, a typical heat transfer coefficient (U-value) of 362.5 $W/m^2{\circ}C$ has been [33]. The pressure values at the top and the bottom of the deethanizer column are taken from [32]. The inlet temperature and pressure are assumed to be the same as they were in other gas processing unit operations. Five deethanizer columns are installed to sustain a high feed rate. The parameters for equipment in the NGL recovery unit are presented in Table 3.

Table 3: Equipment parameters in an NGL recovery unit

Parameter	Value	Unit	Reference/Comments
● Compressor efficiency	80%		[32]
● Feed rate	7154.95	kmol/hr	Calculated for 10 MTPA liquefaction capacity
● Plate inlet gas pressure	6.78	MPa	[13]
● Plate inlet gas pressure	311	K	
● Deethanizer top pressure	452	psig	[4]
● Deethanizer bottom pressure	457	psig	[4]
<u>Deethanizer column</u>			
● Diameter	4.2	m	Calculated using GCAP [19]

• Length	20	m	Calculated using GCAP [19]
Heat exchanger			
• Heat load	8.2	MW	[13]
• Area	194	m^2	Calculated using GCAP [19]
Compressors			
• Power consumption	8.2	MW	[5]

When we substitute the values of the diameter and length of the deethanizer column from Table 3 in Equation 8, we get the cost of one column. We used Equations 4 and 9 to estimate the cost of the heat exchangers and compressors, respectively.

2.2.4. Liquefaction unit

The liquefaction process considered in this paper is the propane pre-cooled mixed refrigeration (APCI C_3MR) process. This process dominates the LNG market with a 77% share [34]. Before the natural gas flows into the main cryogenic heat exchangers, it is precooled to 16°C in the high-pressure propane cooler and further cooled to -35°C in the medium- and low-pressure propane coolers. The large surface area of the main cryogenic heat exchanger helps in efficient heat transfer from the feed gas and cools the gas to -155°C. The gas exits as LNG and to reduce its pressure, it is sent to expanders, after which it is routed to storage ranks [10]. The number of compressors considered in this paper for propane cycle and mixed refrigerant (MR) cycle is 1 and 2, respectively [10]. The heating load values of theses compressors correspond to the optimal liquefaction process cycle [34]. The gas feed rate pertains to liquefaction capacities of 5 MTPA. The surface areas for the heat exchangers were estimated using GCAP [19]. The parameters for the equipment considered are listed in Table 4. The main cryogenic and propane heat exchangers, compressors, gas turbines, and expanders are the major cost driving equipment in this process.

Table 4: Parameters for the liquefaction process

Parameter	Value	Unit	Reference/Comments
• Feed temperature	6.76	MPa	[13]
• Feed pressure	311	K	[13]
• Feed rate	19.26×10^6	m^3 /day	Calculated for a 10 MTPA liquefaction capacity plant
• Total power requirement of the compressors	141.86	MW	Calculated for a 5 MTPA liquefaction train [34]

Surface area of heat exchangers			
• Propane cooling heat exchanger	164	m^2	Calculated using GCAP [19]
• Main cryogenic heat exchanger	490	m^2	Calculated using GCAP [19]

Two General Electric (GE) Frame 7 gas turbines provide the power requirement for the compressors. These turbines have a power generation capacity of 88.2 MW [35]. The installation cost of the turbines was calculated using the values of their power output in cost and power correlation as presented in Equation 10. The installation cost for propane compressors and mixed refrigerant compressors was estimated by substituting the power requirements of the compressors in Equation 9. The cost of propane heat exchangers and main cryogenic heat exchanger depends on their surface area and is estimated using Equation 4.

3. Results

3.1. Equipment cost

In this section, the results of the paper, i.e., the cost of equipment in each unit operation, are presented and discussed. The estimated cost of one gas-sweetening unit is $6.3M, in which the major cost contributing equipment are the heat exchanger, re-boiler, and regeneration column.

The remaining pieces of equipment each contribute less than 10% of the total cost. Since there are 4 gas sweetening units in the plant designed for this paper , the total cost is $25.2 M. The cost distribution for this unit is presented in Figure 4.

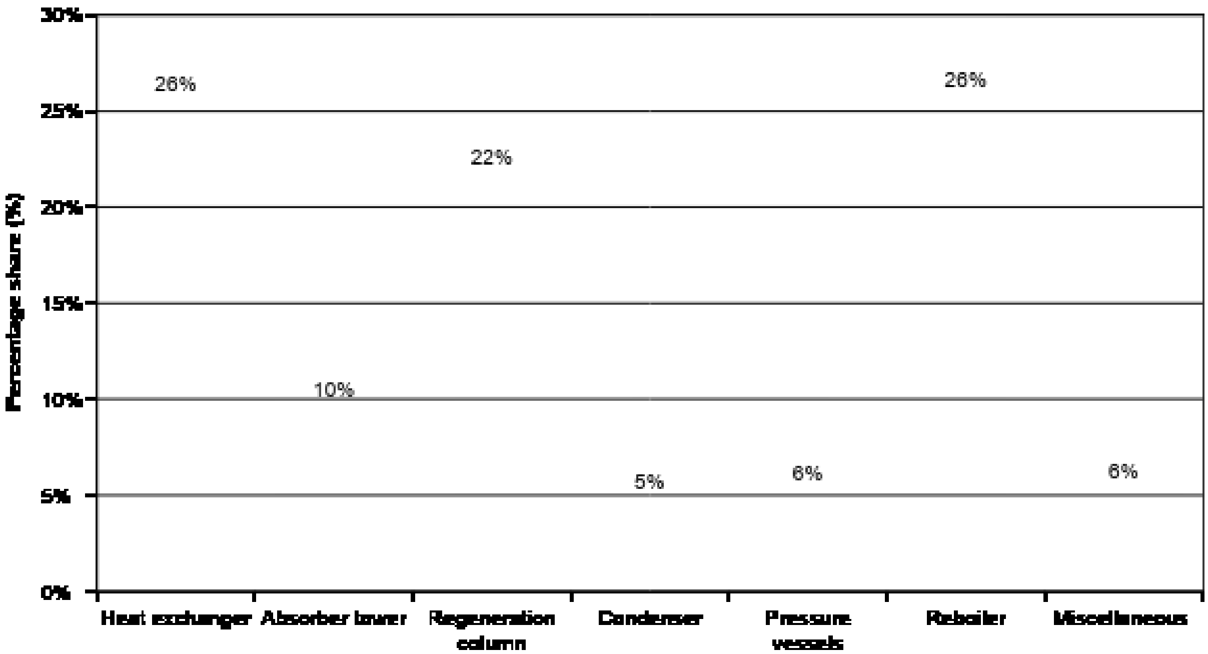

Figure 4: Cost distribution of the equipment in a gas sweetening unit

For the gas dehydration unit, the adsorber tower contributes to the total installed cost, which is estimated to be $9.8M for the designed liquefaction facility. There are five dehydration units available per train, resulting in a total of 10 units for the entire liquefaction plant. In the natural gas liquid recovery unit, the deethanizer column makes up 72% of the total the total cost, followed by compressors (19%). Heat exchangers, vessels, and miscellaneous costs make up 10% of the total cost. There are 2 NGL recovery units per LNG train, and the installed cost of one NGL recovery unit is $19M. Of all the unit operations in natural gas processing, liquefaction is the most capital intensive. The total installed cost of equipment used in liquefaction is $265M, with around 44% of the total cost shared by gas turbines. The second-most cost contributing equipment is the main cryogenic heat exchanger. The cost distribution of different equipment is presented in Figure 5. The summary of capital cost for equipment for the entire liquefaction facility is presented in Table 5.

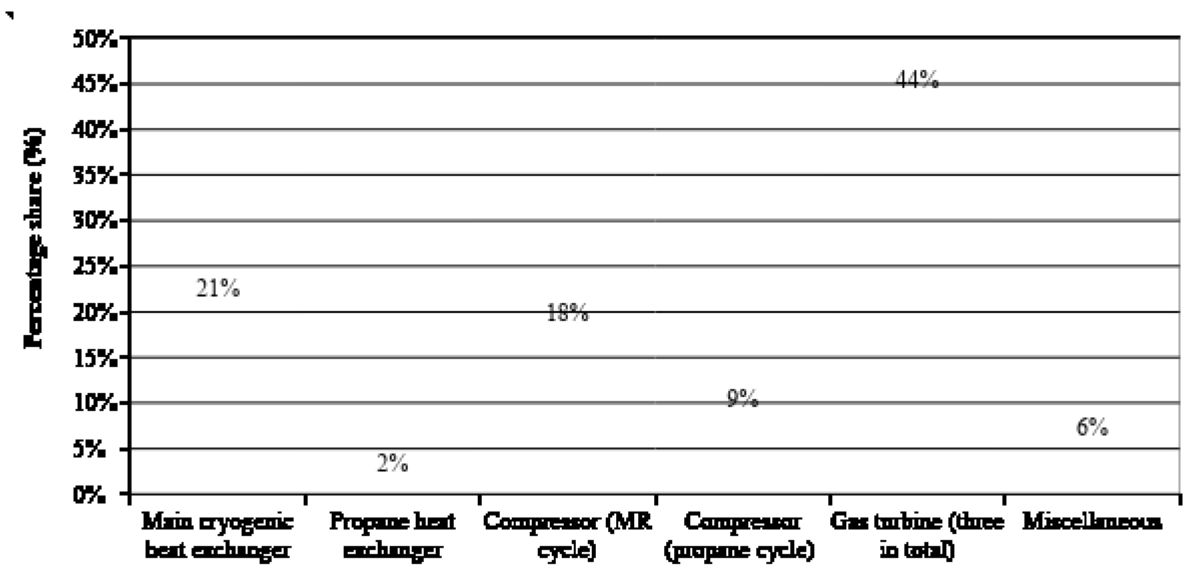

Figure 5: Cost distribution of the equipment in a liquefaction unit

Table 5: Summary of equipment costs for the LNG plant

Operation	Cost (US$)	Percentage share (%)	Comments
Gas sweetening	25.2M	3	Estimated cost of 4 gas sweetening

			units
Dehydration	9.8M	1	Estimated cost of 10 dehydration units
NGL recovery	38.5M	5	Estimated cost of 2 NGL recovery units
Liquefaction	265.8M	33	
LNG storage tanks	461.7M	58	Estimated cost of three storage tanks (each with a storage capacity of 160 K m3 accommodating a ship delay of 7 days and price of $150 M per tank [36])
On-site cost	801.1M		
Total installed equipment cost	1.9B		Calculated using empirical relationship provided in Ref. [37]

3.2. Cost estimation of delivering Canadian LNG to Asia

The total cost of delivering Canadian LNG to Asia (China, Japan, and India) consists of five cost components, namely, feed gas price at the wellhead, pipeline transpiration cost, liquefaction facility capital expenditure (CAPEX), operational expenditure (OPEX), and shipping cost. In this section, all of these costs are discussed in detail and total delivery cost of LNG is estimated. Two supply sources of raw natural gas (Horn River and Montney shale reserve) are considered in this study. The Horn River shale reserve has a gas supply break-even cost of \$4.74/GJ, which includes the wellhead and pipeline transport cost, whereas the liquid rich Montney has a gas supply cost of \$3.48/GJ [38] (see Table 5). The lower heating value of natural gas (37.3MJ/m^3) and the feed value (1.5 bcf/d) corresponding to a 10 MTPA plant were used to estimate total natural gas feed cost. Construction labor costs depend on the number of laborers, labor cost, country, and the employment industry. This cost was calculated based on the average wages of construction laborer employed in Canada's oil and gas sector [39] and the total number of workers expected to be employed in the Kitimat LNG plant [40]. Due to the unavailability of Canada-specific peer-reviewed data, the project management labor and engineering labor costs were estimated using the "percentage of installed equipment cost method" provided by West et al. [24]. This method is generally used for preliminary paper estimates and has an accuracy range of ±20-30 percent [24]. In the Kitimat LNG plant, General Electric gas turbines would be installed and would generate electricity at the plant. The water cost is negligible compared to the operations and maintenance cost. Therefore, the overall utility costs are negligible and not accounted for in this study.

The total investment cost is calculated using the methods presented by Douglas [37] and using Equation 13. These costs were amortized assuming a 12% discount rate (r), and a plant life (n) of 25 years. By substituting the total investment cost and operations cost in Equations 12 and 14, respectively, we find the total amortized investment and total operations cost. The cost of liquefying one gigajoule of natural gas is shown in Table 6. The total product cost is $7.8/GJ, if the gas supply source is Montney and is $9.1/GJ, if the gas supply source is Horn River. All the cost values mentioned above have been summarized and presented in Table 6.

Table 6: Cost summary for a two-train 10 MTPA Canadian natural gas liquefaction facility

	Cost (US$)	**Reference/Comments**
Capital cost		
Equipment cost	1.9B	
Construction labor		
Project management labor	3.7B	Calculated by using project management labor's fraction (1.94) of total installed equipment cost [41]
Construction labor	6.7B	Calculated using the number of construction laborers working in the Kitimat LNG facility and the average salary of oil and gas laborers

		in Canada
Engineering labor	2B	Calculated using engineering labor's fraction (1.05) of total installed equipment cost [41]
Total capital expenditure (CAPEX)	$1200/tpa	Calculated by dividing the total estimated capital cost by the liquefaction capacity
Operations and maintenance cost		
Natural gas supply cost	$3.48/GJ (Montney)	Includes a break-even wellhead cost of $2.63/GJ and a transportation tariff of $0.84/GJ [38]
	$4.74/GJ (Horn River)	Includes a break-even wellhead cost of $3.74/GJ and transportation tariff of $1.0/GJ [38]
Total operational expenditure (OPEX)	$48/tpa	Assumed to be 4% of the total capital expenditure
Amortized cost		
Amortized CAPEX	$3.6/GJ	Calculated using a 12% rate of return and a

Amortized OPEX	$0.8/GJ	plant life of 25 years
Total product cost	$7.8/GJ (Montney), $9.1/GJ (Horn River)	Sum of amortized investment and operations and maintenance cost

After the liquefaction process, LNG carriers ship LNG. The cost of shipping would depend on the type of carrier, its propulsion system and fuel consumption, hiring rate, etc. An in-depth techno-economics analysis of shipping natural gas in the form of LNG to Asian countries (Japan, China, India) can be found in a paper in preparation by Raj et al. [42]. The shipping cost values reported in Raj et al. [42] have been adapted in this paper . The break-even cost of delivery to three Asian countries has been presented in Figure 6. The delivery cost is the price at which the Canadian LNG must be sold in these Asian countries to recover all the costs incurred. For Japan the delivered cost of Canadian LNG ranges from $8.2/GJ to $10.1/GJ with a base case estimate of $9.15/GJ. The corresponding cost for China is $9.28/GJ with a range similar as that of Japan. For India, the delivered cost is 8% higher than for Japan due to the greater shipping distance.

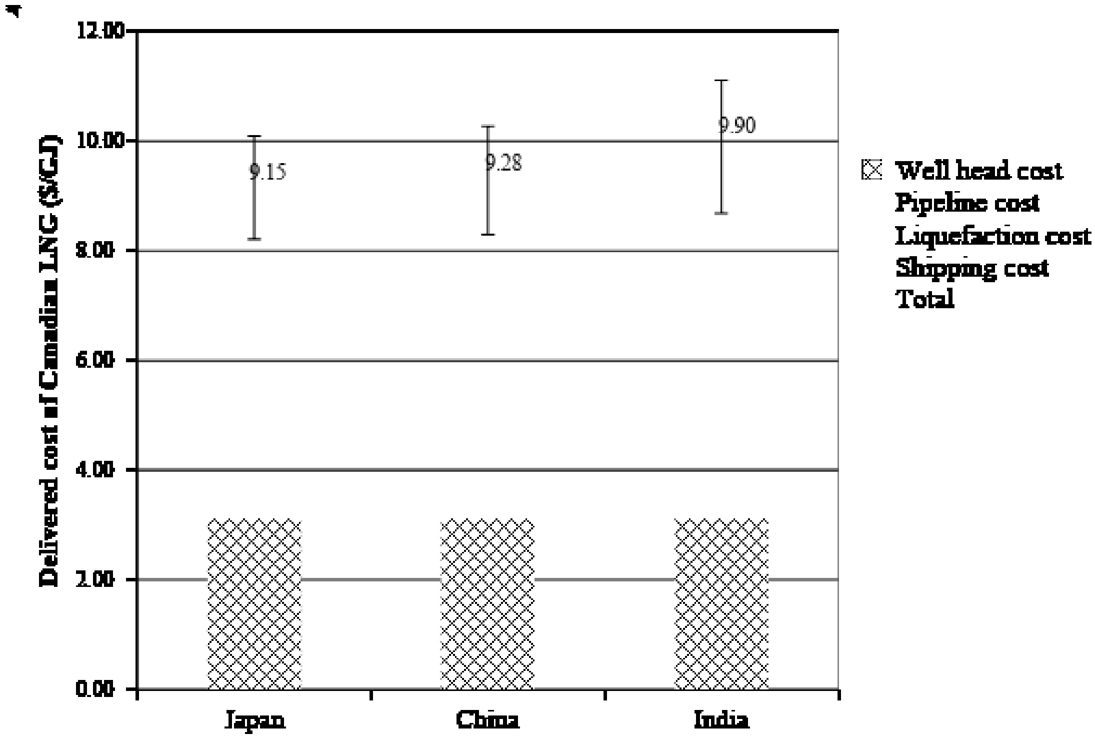

Figure 6: Break-even cost of delivery of Canadian LNG to Asia.

3.3. LNG plant scale analysis

For this section, we estimated the scale factor associated with the capital cost of LNG facility construction. Figure 7 shows some of the LNG projects around the globe whose capital cost [43] and annual liquefaction capacity [44] were considered to determine the dollar per ton value of LNG plants. The capital cost of all the projects was adjusted for inflation and exchange rates between their completion year and 2014. The value of the scale factor exponent is estimated to be 0.69. This demonstrates economies of scale in the construction of LNG plants. Using LNG project data and power sizing exponents, an equation (Eq. 15) for the cost of LNG projects was formulated. This equation has been estimated using the power- sizing model. This model accounts explicitly for economies of scale. To estimate the cost of B based on the cost of comparable item A, we use the equation

$$\text{Cost of B} = (\text{Cost of A}) \left[(\text{"Size" of B}) / (\text{"Size" of A}) \right]^{x}$$

where x is the appropriate power-sizing exponent, available from a variety of sources. An economy of scale is indicated by an exponent less than 1.0 An exponent of 1.0 indicates no economy of scale, and an exponent greater than 1.0 indicates a diseconomy of scale.

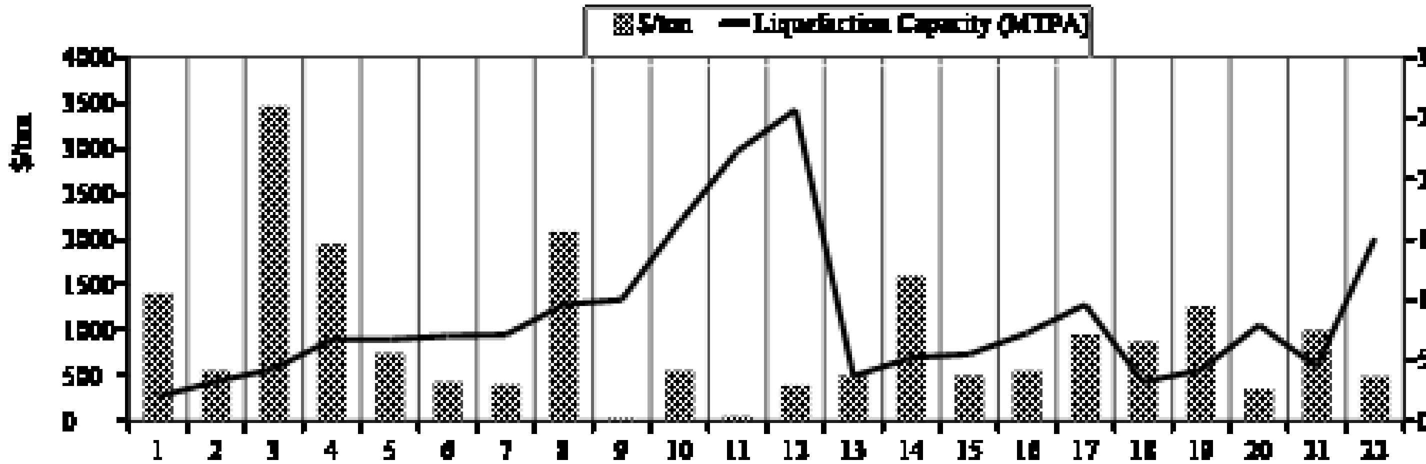

Figure 7: The cost of liquefying one ton of LNG ($/ton) vs. LNG plant capacity (MTPA)

3.4. Sensitivity analysis

For this section, we conducted a sensitivity analysis to assess the impact of various parameters on the total product cost. Five parameters, namely, the discount rate, LNG facility capital expenditure (CAPEX), operating expenditure (OPEX), natural gas wellhead cost, and pipeline transport cost were varied to assess their significance. A discount rate of 12% was considered in the base case study. For the purposes of the sensitivity analysis, the discount rate was varied from 8% to a maximum of 24%. All other parameters were varied within a ±100% range. The results of this analysis are presented in Figure 8 below. It is clear from the results that CAPEX is the most influential parameter on overall product cost followed by gas wellhead cost and the discount rate. The CAPEX cost considered in the base case is $1200/tpa. This cost is high for Canadian LNG projects since most of the projects are greenfield. The operational expenditure (OPEX) of the LNG facility and the transportation cost were found to have a similar impact on the total product cost.

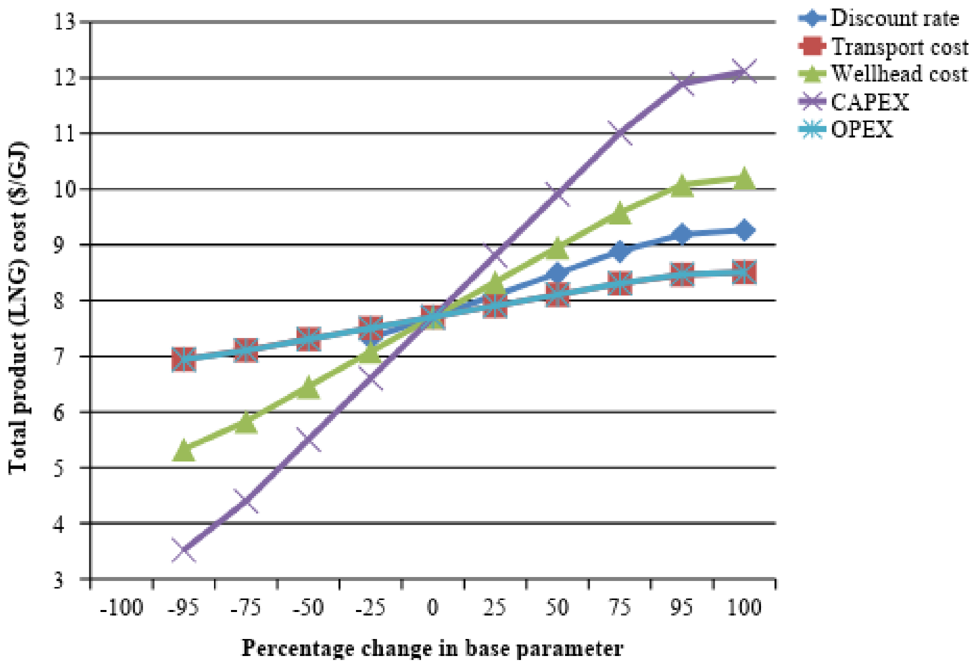

Figure 8: Sensitivity analysis for total product (LNG) cost

A sensitivity analysis for the equipment was also performed. The variations in equipment cost with changes in parameter are shown in Figures 9 to 14. The costs represented are shown with a ±5 percent variation. Figure 9 represents gas turbine cost variations with respect to the power a turbine generates. Gas turbines are the main cost contributor in the liquefaction process, as shown in section 2.4. A wide variation in cost for different values of power generated can be observed. The cost curve is a concave curve opening downwards and showing economies of scale involved. Figure 10 shows the variation of compressor costs with power requirement. The cost varies between 8 and 10 million U.S. dollars for a power range of 30 MW to 50 MW. Figure 11 represents the variation of heat exchanger costs with surface area. Figure 12 represents variations of condenser cost with surface area. Figure 13 shows variations of absorber tower cost with changes in diameter and a fixed tower length of 8.14m. Figure 14 shows variations of adsorber cost with varying lengths and a fixed diameter of 4.02 m.

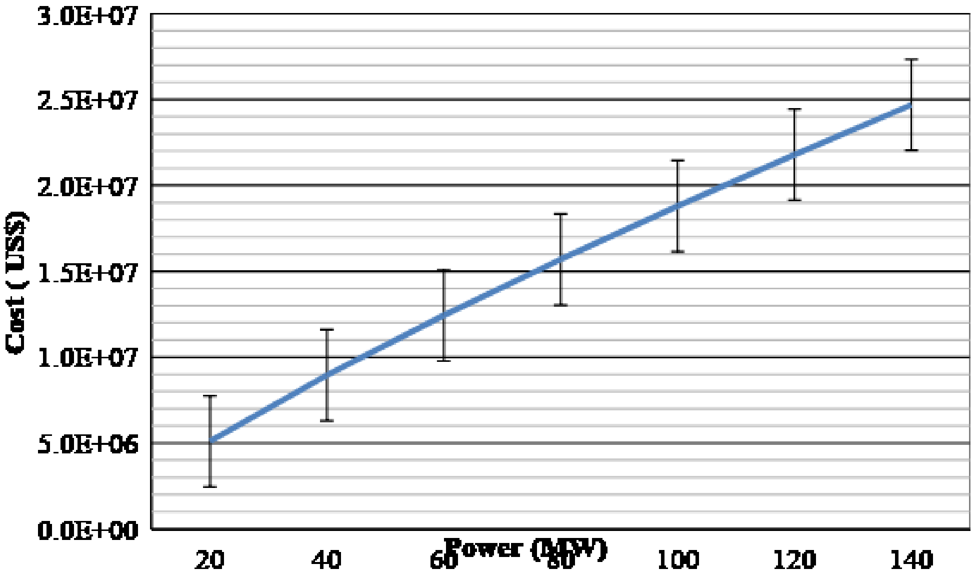

Figure 9: Cost versus power graph for gas turbines

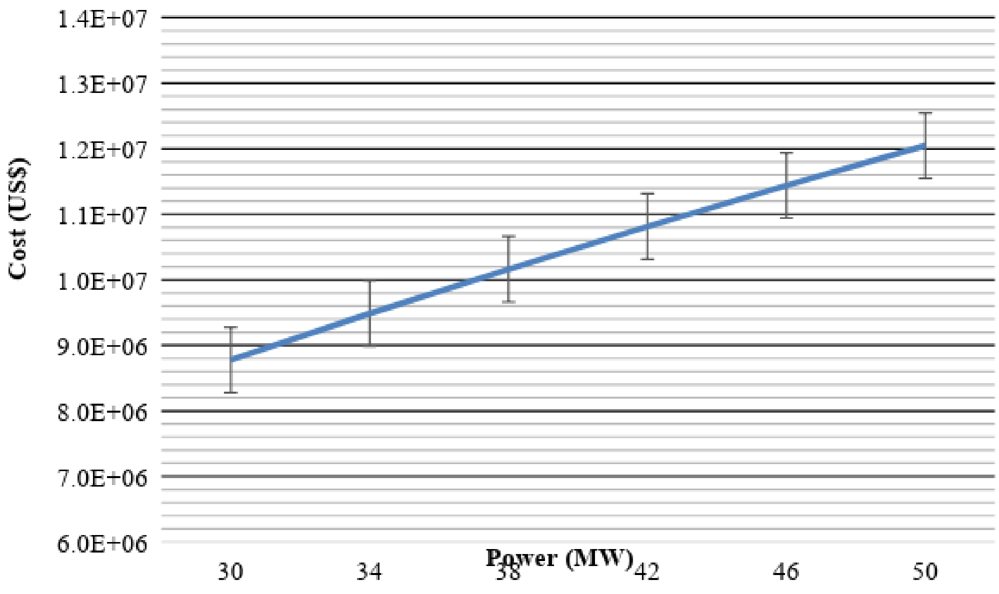

Figure 10: Cost versus power graph for compressors

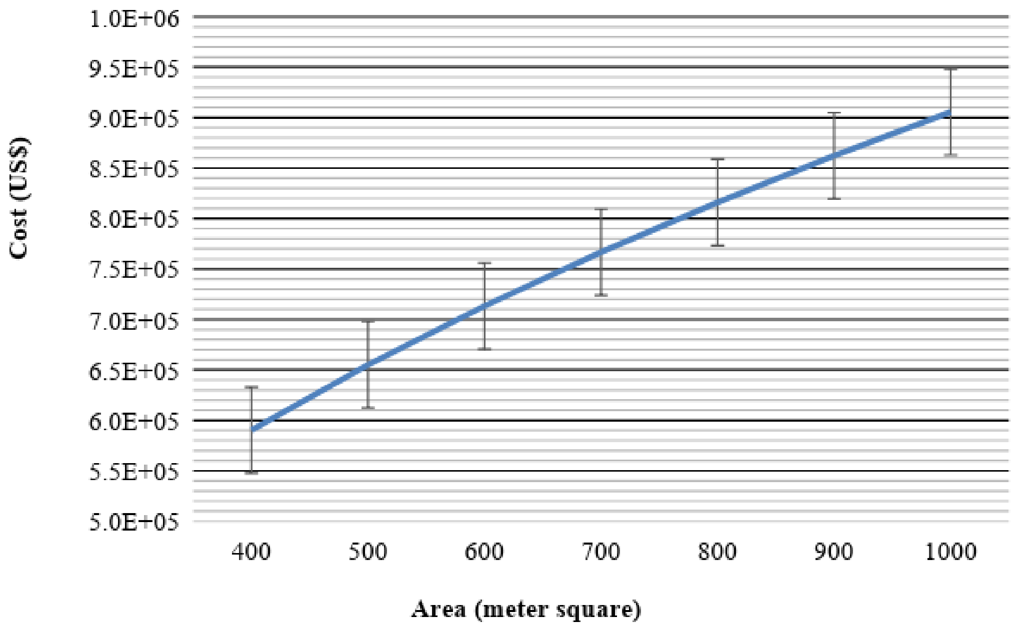

Figure 11: Cost versus area graph for heat exchangers

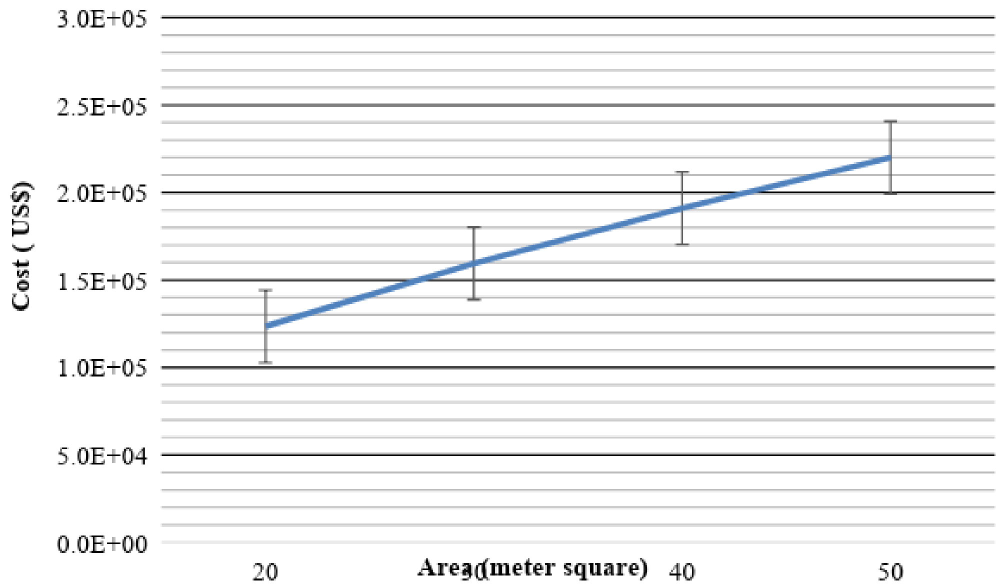

Figure 12: Cost versus area graph for condenser columns

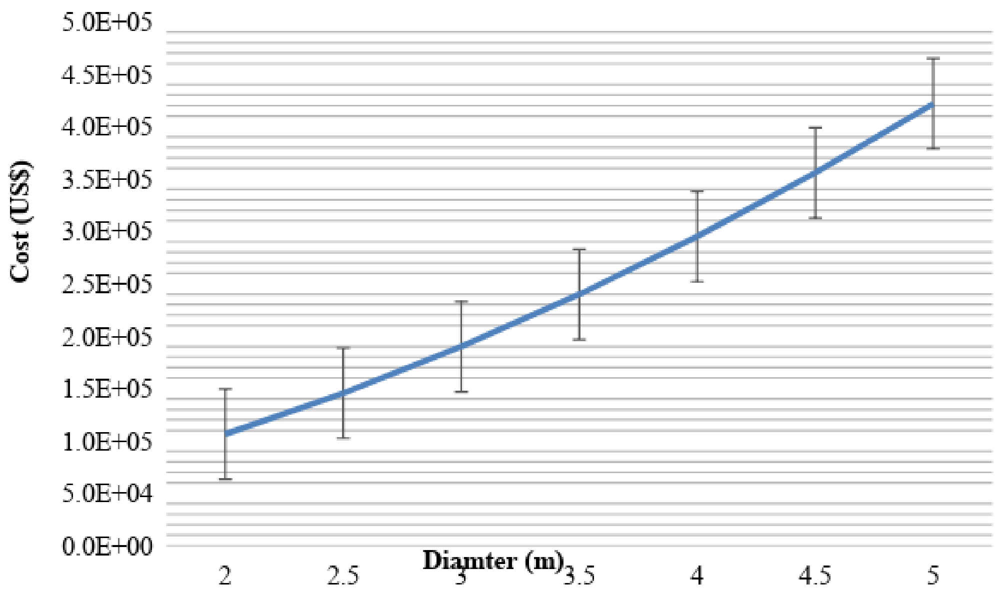

Figure 13: Cost versus diameter graph for absorber columns

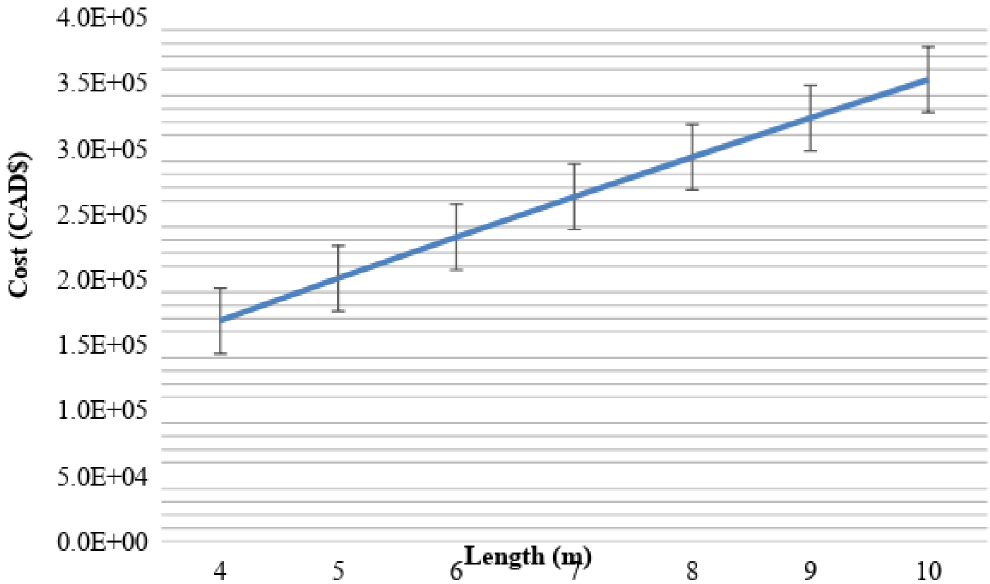

Figure 14: Cost versus length graph for absorber columns

4. Conclusion

The objective of this paper was to conduct a data-intensive paper to estimate the cost of equipment installed in a 10 MTPA LNG plant in Canada through development of techno-economic models and cost correlations. To this end, the equipment cost for each LNG process and the liquefaction cost of one gigajoule of natural gas were calculated. It was found that the liquefaction unit makes up the majority of costs incurred in liquefaction. Thus, any slight improvement in liquefaction technology or the creation of optimal conditions through process optimization software would greatly reduce the overall project cost. The total product cost is \$7.8/GJ, if the gas supply source is Montney and \$9.1/GJ, if the gas supply source is Horn River. This cost includes the gas wellhead cost, pipeline tariff, and the liquefaction cost. Apart from LNG facility capital expenditure cost, the gas supply cost is a key parameter that can significantly impact the total product cost. Hence, reducing gas supply cost by using more economic gas extraction and recovery techniques can bring down product cost. If shipping costs are added, we get the total delivery cost of Canadian LNG to Asian countries. For Japan, the delivered cost of Canadian LNG ranges from \$8.2/GJ to \$10/GJ with an average estimate of \$9.15/GJ. Therefore, Canadian LNG projects require a minimum of \$62/barrel in the central case assumptions, if an average 14.5% slope for Japanese contracts indexed on the Japanese Crude Cocktail Price (JCC) is assumed. Hence it is clear that LNG projects in Canada are very susceptible to the oil prices in Japan. In China, however, there is a wide gap among citygate natural gas prices from different sources. Natural gas citygate prices in Shanghai range from \$8/GJ (domestic gas transported through the West-East Pipeline) to \$13/GJ (Turkmenistan gas imports) [45]. The delivered cost of Canadian LNG lies midway in this range and hence the imported LNG from Canada may be a cheap alternative source of LNG for China at a time when Chinese policy makers are trying to diversify their LNG import mix.

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Appendix 1: List of Equations

Number	Equation	Reference/Comments
1	$C_{AT}= 1.7C_b+43.37V_p+464.63D_a^{0.74}L_a^{0.71}$	[23]
2	$C_b = 1.218\ \exp^{(6.629+0.1826(\ln Wa)+0.02297(\ln Wa)(\ln Wa))}$	[23]
3	$C_R = 1.218\ (f_1C_b+Nf_2f_3f_4C_t+C_{pt})$	Here values of f_1 and f_2 correspond to stainless steel 304,

		values of f_3 and f_4 correspond to tray types and their number; C_b, C_t and C_{pt} depend on the weight, length, and diameter of the absorber column [23]
4	$C_{HE} = 35969(A_{HE})^{0.47}$	[28], [23]
5	$C_{condenser} = 18707(A)^{0.63}$	[28]
6	$C_{Reboiler} = 2045(A)^{0.9748}$	[28]
7	$C_{AD} = 28712+3036*(W_d)^{0.48}$	[28]
8	$C_D = 102536*D_d^{0.63}*L_d^{0.80}$	[28], [24]
9	$C_C = 1065470*(P_c)^{0.62}$	[23]
10	$C_{GT} = 0.69(HP)^{0.81}$	[23], Horsepower of the gas turbines correspond to the GE Class 7 gas turbine power output
11	$C_T = C_{IA} + C_{OA}$	Total LNG product cost is the sum of the amortized total investment cost and amortized operations and maintenance cost [37].
12	$C_{IA} = (r*(1+r)^n/L_c)*C_I$	Amortized investment cost calculation based on a 12% rate

		of return and a plant life of 20 years
13	$C_I = 2.36 * C_{on}$	[37]
14	$C_{OA} = C_O / L_c$	Amortized operations and maintenance cost based on the total annual liquefaction capacity
15	$C_{LNG\ Plant} = 1.61 * (L_C)^{0.69}$	Generalized expression developed considering the cost of various LNG projects across the globe.

Appendix 2: LNG projects in Canada

Location	Name	Capacity	NEB export application status	Length (Years)	Expected Start Date	References
Kitimat, B.C.	Douglas Channel Energy Project	1.8	Approved	20	2015	[46]
Kitimat, B.C.	Kitimat LNG Terminal	5	Approved	20	2017	[47]
Kitimat, B.C.	Haisla Cedar	14.5	Under review	25		[48]
Kitimat, B.C	NewTimes Energy LNG	12	Under review	25		[49]
Kitsault, B.C.	Kitsault	5	Under review	25	2017	[50]
Woodfibre, B.C.	Woodfibre LNG	2.1	Approved	25	2017	[51]
Kitimat or Prince Rupert,	Triton LNG	2.3	Approved	25	2017	[52]

B.C.						
Prince Rupert, B.C.	Orca LNG	24	Under review	25		[53]
Sarita Bay, B.C.	Steelhead LNG	30	Under review	25		[54]
Lelu Island, Port Edward, B.C.	Pacific Northwest LNG	12	Approved	25	2018	[55]
Coos Bay, Ore.	Jordan Cove LNG	6	Approved	25	2018	[56]
Campbell River, B.C.	Discovery LNG		NA	NA	2019	[57]
Kitimat, B.C.	LNG Canada Terminal	12	Approved	25	2020	[58]
Kitimat or Prince Rupert, B.C.	WCC LNG	12.50	Approved	25	2021-2022	[59]

Ridley Island, Prince Rupert, B.C.	Prince Rupert LNG	14	Approved	25	2021	[60]
Grassy Point, B.C.	Aurora LNG	24	Approved	25	2021-2023	[54][54]
Stewart, B.C.	Stewart Energy LNG	17	Under review	25	2017	[61]
Vancouver, B.C.	Tilbury LNG	3	Under review	25	2016	[5]

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