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REFINING BITUMEN: COSTS, BENEFITS AND ANALYSIS

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REFINING BITUMEN:
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Refining Bitumen: Costs, Benefits and Analysis

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Executive Summary

The unlocking of unconventional resources for both oil and natural gas has resulted in discounted North American crude oil and natural gas prices in relation to the rest of world. As a result, many North American refineries benefit from having access to lower priced feedstock making the finished products more competitive. Canada is in a unique position because Canada produces far more oil and gas than can be consumed domestically. With bitumen production slated to increase over time and the US taking advantage of overseas markets, there have been questions about why Canada has not developed a more integrated value-added chain within the country.

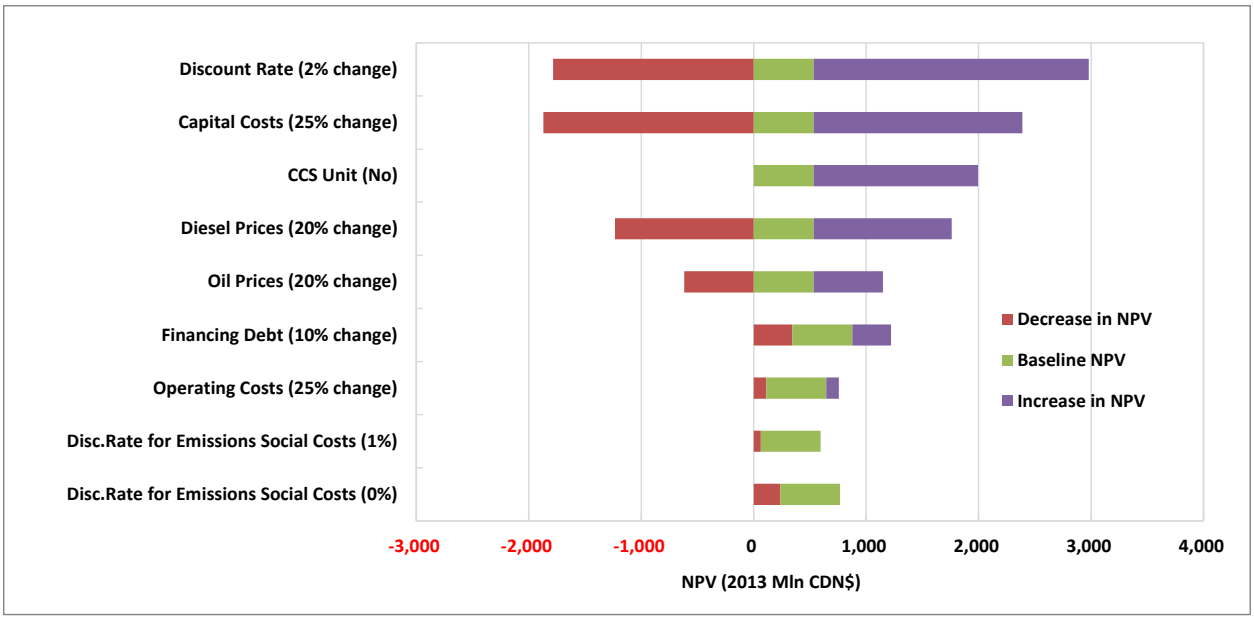
In this study, CERI conducted a cost-benefit analysis (CBA) for a greenfield refinery using up-to-date information[1] to estimate the costs and benefits of the project. The CBA results suggest that a greenfield commercial refinery project is net socially beneficial across a typical discount rate range (13-15 percent) for the refinery business. The net present value (NPV) of a greenfield refinery in Alberta with a carbon capture unit installed is a net benefit of almost $533 million.[2] However, if the average West Texas Intermediate (WTI) price drops below $85 over the life of the project[3] – the project would be a net cost to society. There is the potential for the project to be a net cost given that the analysis excluded a number of environmental costs such as potential greenhouse gas (GHG) damage costs from final consumption emissions, water pollution, opportunity cost of water consumption, and potential human health impacts.

A sensitivity analysis was conducted together with the CBA to examine how alternative values for particularly uncertain parameters affect NPV. The economics of a refinery are complex and depend on many factors. Profits or losses result primarily from the difference between the cost of inputs and the price of outputs. In the oil refining business, the cost of inputs (crude oil) and the price of outputs (refined products) are both highly volatile, influenced by global, regional, and local supply and demand changes. Refineries must optimize production against a backdrop of changing environmental regulation, changing demand patterns and increased global competition among refiners in order to be profitable. Eight different parameters were analyzed that would influence the NPV of a project: discount rate, capital costs, carbon capture unit, the price of diesel, the price of crude oil, financing costs, operating costs, and discount rate for social costs.

The results of the sensitivity analysis are presented in Figure E.1. The baseline NPV of the project (green bar) is positive $533 million. Changing the value of the variables affects the NPV of the project. For example, if a carbon capture unit is omitted, the capital cost will decrease, emissions will increase, and the NPV will increase to $2.0 billion.

[1] The cost estimates were taken from the recent cost evaluation of constructing the North West Upgrader.
[2] The NPV is $532.74 million with an assumed 15% discount rate and a 50-year project life.
[3] At the time of writing, the WTI price was just above US$77/bbl.

Figure E.1: NPV Sensitivity Analysis



Source: CERI

Not surprising, the choice of the discount rate will affect the economics of a refinery. In this case, increasing the discount rate to 17 percent drops the NPV of the refinery to -$1,251 million, whereas decreasing the discount rate to 13 percent will boost the NPV to $2,980 million.

After the discount rate, changes to capital costs have the greatest impact on NPV. Oil refining is a capital-intensive business. Planning, designing, permitting and building a new medium-sized refinery is a 5-7 year process with costs ranging from $7-10 billion, not including land acquisition. The cost varies depending on the location (which determines land and construction costs[4]), the type of crude to be processed and the range of outputs (both of the latter affect the configuration and complexity of the refinery), the size of the plant and local environmental regulations. Varying capital costs by 25 percent will change the NPV by almost the same magnitude, but in the opposite direction.

After the refinery is built, it is expensive to operate. Fixed costs include personnel, maintenance, insurance, administration and depreciation. Variable costs include crude feedstock, chemicals and additives, catalysts, maintenance, utilities and purchased energy (such as natural gas and electricity). To be economically viable, the refinery must keep operating costs such as energy, labour and maintenance to a minimum. Like most other commodity processors (such as food, lumber and metals), oil refiners are price takers: in setting their individual prices, they adapt to

[4] For example, building a comparable project on the US Gulf Coast costs less than half of what it does to erect a plant in Alberta according to IHS CERA's "Extracting Economic value from the Canadian Oil Sands: Upgrading and Refining in Alberta (Or Not)?"

market prices. In the sensitivity analysis the 25 percent increase in operating costs reduced the NPV by $112 million and vice versa.

Other factors that could affect project economics are the prices of crude oil and diesel, with diesel prices having a larger impact than crude prices. Dropping diesel and oil prices by 20 percent over the project life makes the project's NPV negative and vice versa.[5] For example, reducing diesel prices by 20 percent causes the NPV to be -$701 million. Since refineries have little or no influence over the price of their input or their output, they must rely on operational efficiency for their competitive edge.

The social costs of emissions varied depending on the chosen discount rate for these costs. Generally, the lower the discount rate, the more social cost incurred in the future is placed on society today. In other words, the cost of polluting has more "value" today than what's left for future generations. Hence, choosing a smaller discount rate reduces the NPV of the project. Table E.1 summarizes the NPVs for all the cases.

Table E.1: Sensitivity Cases

Variable	Base Line	Change to the Variable	Resulting NPV	Change from Baseline NPV
CCS Unit	CCS installed	No CCS unit	$1,994.1	$1,461.34
Discount Rate	15%	+2%	-$1,251.1	-$1,783.9
		-2%	$2,979.9	$2,447.1
Oil Prices[6]		+20%	$1,150.3	$617.5
		-20%	-$84.8	-$617.5
Diesel Prices[7]		+20%	$1,761.6	$1,228.8
		-20%	-$700.6	-$1,233.4
Capital Costs	$8.5 billion	+25%	-$1,336.5	-$1,869.2
		-25%	$2,389.2	$1,856.4
Operating Costs	$164 million/year	+25%	$420.5	-$112.2
		-25%	$645.0	$112.2
Disc. Rate for Emissions	3%	0%	$297.3	-$235.4
		1%	$469.7	-$63.1
Debt Financing	40%	+10%	$188.6	-$344.1
		-10%	$876.9	$344.1

Source: CERI

[5] The differential between diesel and oil prices is not constant. The differential narrows in the latter part of the time period as oil prices grow faster than diesel prices.
[6] See Chapter 2, Revenues section under Benefits, page 17.
[7] Ibid.

Chapter 1: Introduction and Background Information

Introduction

The unlocking of unconventional resources for both oil and natural gas has resulted in discounted North American crude oil and natural gas prices in relation to the world. As a result, many North American refineries have benefitted from having access to lower priced feedstock making the finished products more competitive. The US in particular has been able to increase distillate and gasoline runs in the US Gulf Coast for export to Latin American, European and West African markets. Canada is in a unique position because it produces far more oil and gas than can be consumed domestically. Furthermore, higher oil and gas prices have improved Canada`s economic performance despite challenges regarding market access and various environmental concerns. With bitumen production slated to increase over time and the US taking advantage of overseas markets, there have been questions about why Canada has not developed a more integrated value-added chain within the country.

Adding a value-added industry within Canada has taken two directions: One is to refine crude within Alberta (AB), British Columbia (BC), or Saskatchewan (SK) and use the products domestically or for export to the US and possibly Asia-Pacific markets; the other is for eastern Canadian refineries to have access to discounted domestic crudes. For the former, only the North West Redwater Partnership in Alberta is planning to build a refinery (North West Upgrader)[1] to meet a low-sulphur diesel deficit in Alberta.[2] The other proposals are to send crude eastward to supply eastern Canadian refineries to reduce their dependence on more expensive foreign crude oil. The question of whether refining is the best value-added investment has been subject to great debate and no full scale analysis has been done to answer the question of whether additional refining capacity within Western Canada is of net benefit to Canadians. A recent study[3] commissioned for the Alberta Federation of Labour (AFL) assessed the economics of building and operating an in-province upgrading, refining, and associated value-added petrochemical complex utilizing a high level operating cash flow model. CERI's study examines the costs and benefits of building a new refinery in Western Canada with a focus on highlighting the welfare impacts on society for the proposed project. These impacts include economic, social and environmental impacts.

Most provincial regulators require that a project proponent submits an application for the project together with an Environmental Impact Assessment (EIA), a formal document that is used to

[1] North West Upgrading has partnered 50/50 with CNRL to form the North West Redwater Partnership to build a bitumen refinery with a carbon capture unit.
[2] Alberta Economic Development Authority (AEDA). "Fuel Shortages in Alberta and How to Fix Them". June 2011. http://aeda.alberta.ca/media/6415/fuel_shortages_how_to_fix.pdf. Accessed on December 10, 2014.
[3] Competition Disputes Regulation (CEG). "In-Province Upgrading Economics of a Greenfield Oil Sands Refinery". April 2014. Prepared for the Alberta Federation of Labour.

predict the environmental consequences (positive or negative) prior to the decision to move forward with the proposed project. The EIA highlights some of the economic effects of the project but it is not reflective of the net social benefit of the project because it does not account for opportunity costs of the resources used in the project, costs incurred by government, impacts on other players (if any) operating in the area and social environmental impacts. Such costs are an economic externality of the project that should be considered. The cost-benefit analysis (CBA) provides a robust method for evaluating the costs and benefits (including both economic and non-economic impacts) of a project or policy change in today's dollars to society as a whole. This method is not currently used by the regulatory agencies when making a decision to approve or reject a project, but it might serve as an additional tool for them to rank and assess options and decide whether to implement them. The AFL study concluded that even though the economics of an in-province upgrading, refining, and associated value-added petrochemical complex suggest the project to be profitable, "…the onus is likely to be on the Government of Alberta to move it forward". If this is the case, then CBA might be the preferred economic evaluation method.

The assessment of building and operating a greenfield refinery within the scope of this study uses the same mass balance and yield assumptions as set out in the EIA of the North West Upgrader. As part of the sensitivity analysis, a scenario to build a refinery without a carbon capture unit is also presented. This and other scenarios were created to assess the advantages and disadvantages of this debate, and to include environmental and economic costs and benefits.

This report is broken down into four chapters. Chapter 1 provides a brief introduction and background information on recent historical data of products demand and prices as well as a review of the refining business in North America. Chapter 2 discusses the methodology and assumptions of the CBA for a greenfield refinery in Alberta. Chapter 3 covers the results of CBA modelling and sensitivity testing, uncovering what parameters of the project have a bigger impact on the NPV of the project. Chapter 4 concludes with a discussion of CBA modelling and its limitations as well as conditions under which building a greenfield commercial refinery in Alberta might be a net benefit.

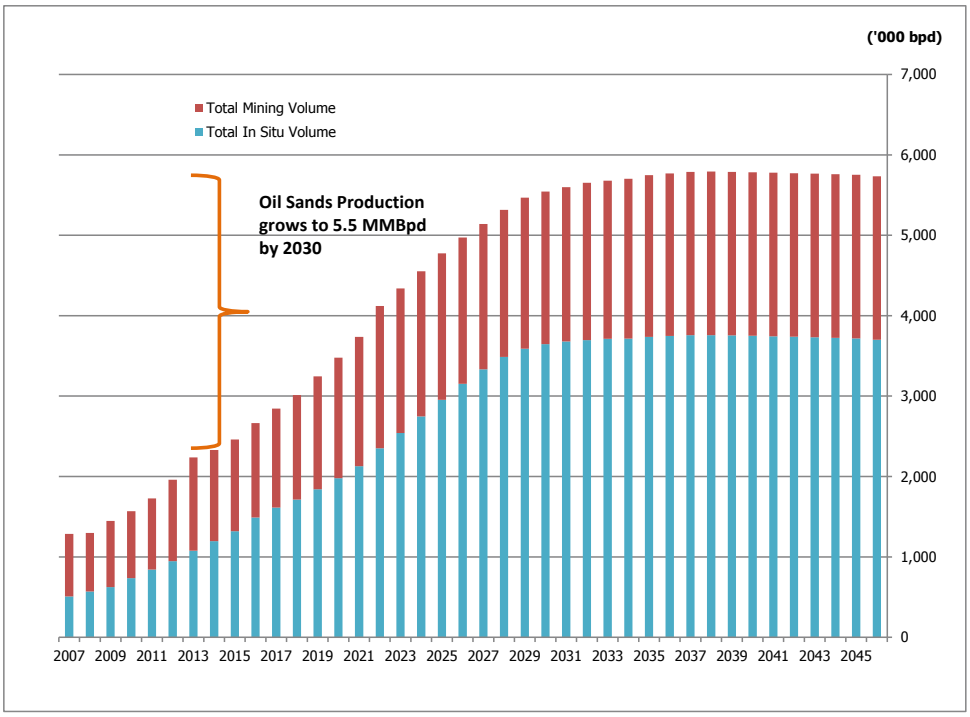
Background Information

Crude Oil Production

There has been substantial investment in non-conventional oil production, particularly in the oil sands. CERI forecasts that production will reach approximately 3 million barrels per day by 2017 and 5 million barrels per day by 2030 (Figure 1.1). This includes upgraded and non-upgraded bitumen. For a detailed summary of the projection forecast please see CERI Study No. 141: Canadian Oil Sands Supply Costs and Development Projects (2014-2048).[4]

[4] http://ceri.ca/images/stories/2014-07-17_CERI_Study_141_Oil_Sands_Supply_Cost_Update_2014-2048.pdf

Figure 1.1: Oil Sands Production Forecast



Source: CERI, CanOils

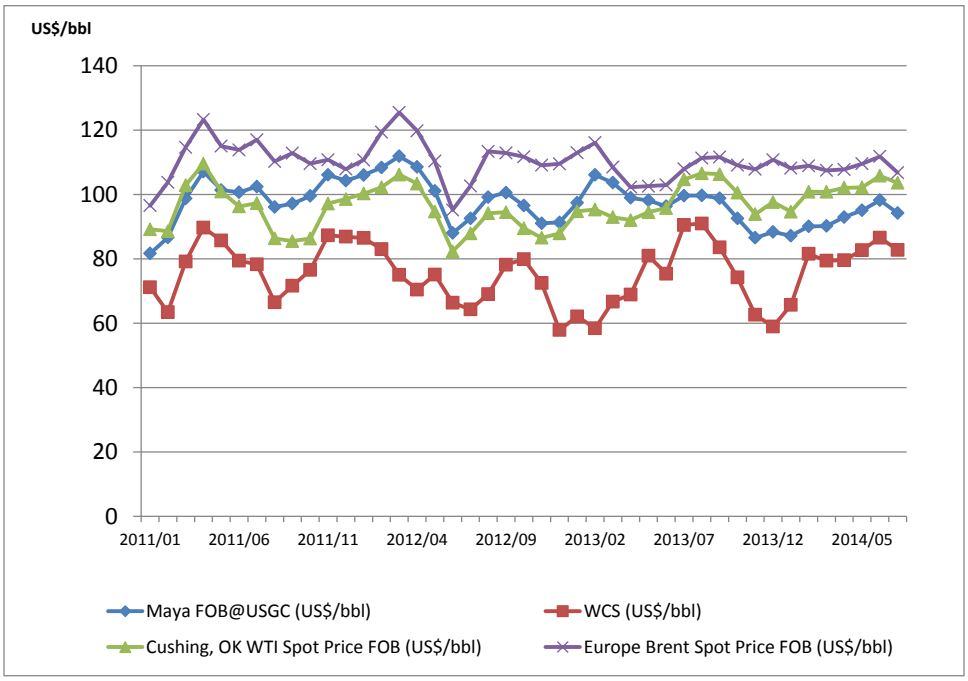
There has also been a surge of non-conventional oil production in the US due to the recent ability to economically extract shale oil. This has resulted in a reversal of declining US oil production and has created a surplus in the domestic market. This excess crude eventually depressed the US benchmark price, West Texas Intermediate (WTI) against its international counterpart, North Sea Brent (Brent) (see Figure 1.2). Concurrently, there had been a rising Brent price due to geopolitical events resulting in supply interruptions in the Middle East and increasing demand in Asia.[5] For the discount to be alleviated within North America the options are to curb back production, increase refining capacity, or transport oil abroad.

Western Canadian Select (WCS) is a heavy crude oil stream which originates from Western Canada. It is comprised of existing Canadian heavy conventional and bitumen crude oils that are blended with diluents. The majority of WCS is exported from Alberta to the already well-supplied US Midwest for refining, and does not have access to tidewater (land-locked). Maya, which originates from Mexico, is a similar heavy crude oil to WCS in terms of quality, yet Maya crude oil prices have been higher due to the fact that Maya is not land-locked and can take advantage of higher international crude prices in the US Gulf of Mexico. The price for WCS averaged US$72.77 per barrel in 2013. For 2013, the WCS price was US$24.41 per barrel lower than the average price of Maya. From 2012 to 2013, the average Maya-WCS differential decreased by 7.6 percent or

[5] Until this past summer, Brent prices were above $100/bbl. Oil prices started to decrease due to excess global supply of crude, slowing demand growth in Asia and OPEC's recent decision not to cut their production.

US$2.00 per barrel. Figure 1.2 showcases the prices of two benchmarks, WTI and North Sea Brent (Brent) and two heavy crudes, WCS and Mexican Maya (Maya).

Figure 1.2: Select Crude Oil Prices



Source: EIA, Alberta Oil Sands BVM and PEMEX Websites

Furthermore, the WTI-WCS differential has caused additional discounting for Canadian crudes because oil sands production in Alberta has been growing more rapidly than the capacity to transport it to refineries capable of processing heavy crudes. Oil sands production is also competing for that refining capacity with oil sourced from other areas. The reversal of the Seaway pipeline, construction of the southern leg of Keystone XL (KXL) and available rail capacity have all recently helped to narrow the light-heavy differential by allowing access to the Gulf Coast refineries that can process heavy oils. However, even if the bitumen reaches the Gulf Coast it still competes with Mexican and Venezuelan heavy oils, but since Canadian producers are much more accustomed to lower prices, they should be well-positioned to compete for refining space, at least in the short term until the market rebalances itself.

With projections showing an increase in production, particularly heavy oil production in Western Canada, combined with a wide WCS-WTI differential that is expected to remain, there has been a debate on whether to expand refining capacity in Western Canada to capture the economic value and jobs of the processing activity, or to export raw bitumen abroad.

Refining

Canada's refinery market should be considered as three separate entities: Western Canada; Ontario; and Quebec and Atlantic Canada. Western Canada is land-locked and refineries have primarily sourced their crude from local production. Ontario is able to access Western Canadian

production via pipelines, Quebec and Atlantic Canada depend on importing crudes because of a lack of pipeline infrastructure, and also the cost of transporting crude from Western to Eastern Canada is more expensive than importing foreign crudes. When US shale oil and Canadian bitumen became discounted relative to international prices, Eastern refineries struggled to remain competitive relative to North American refineries. Furthermore, Canadian oil production has shifted from declining conventional reserves to heavier, higher sulphur crudes such as bitumen. Eastern Canadian refineries that wish to take advantage of lower priced bitumen would have to invest in additional coking and hydrocracking units to process heavier barrels into the same yield of refined products. A greenfield refinery built in Western Canada would require significant capital to be sufficiently complex to process heavy crudes because heavy crude streams do not naturally have high yields of gasoline and diesel. The economics behind whether to invest in these additional coking units is determined by the current and expected spread between light and heavy oil prices. The gain in value for investing in additional units must yield a high enough return to offset the increased costs of building more units.

Refining capacity to process heavy crude is limited because recently the light-heavy crude differential has not been consistently wide enough to cover the cost of installing additional upgrading or refining capacity. In addition North American refineries face competition from abroad as global refining capacity is capable of processing heavy crudes at lower costs than in North America. Aside from the economic challenges, locational and political issues affect access to this processing capacity. Refineries tend to be located close to their markets for refined products.[6] Some of the reasons behind this are that it is less expensive to transport crude oil than refined products, the specifications for gasoline vary across the world, and countries prefer energy security for refined products. For example, historically the US refinery configuration has been to maximize gasoline production but in Asia, refinery configurations support industrial development especially for diesel and petrochemical production.[7]

The variations in product specifications, in environmental regulations, and a short timeframe before degradation of refined products in transit are some of the significant barriers to overcome. Degradation and contamination require product reprocessing that can be costly. In North America, the transportation transit time is overcome by product exchanges where one refiner trades its product with another refiner at a given location. However, for distances to Asia, logistically it can be challenging to match the refined product output from North American refineries with local refined product specifications.

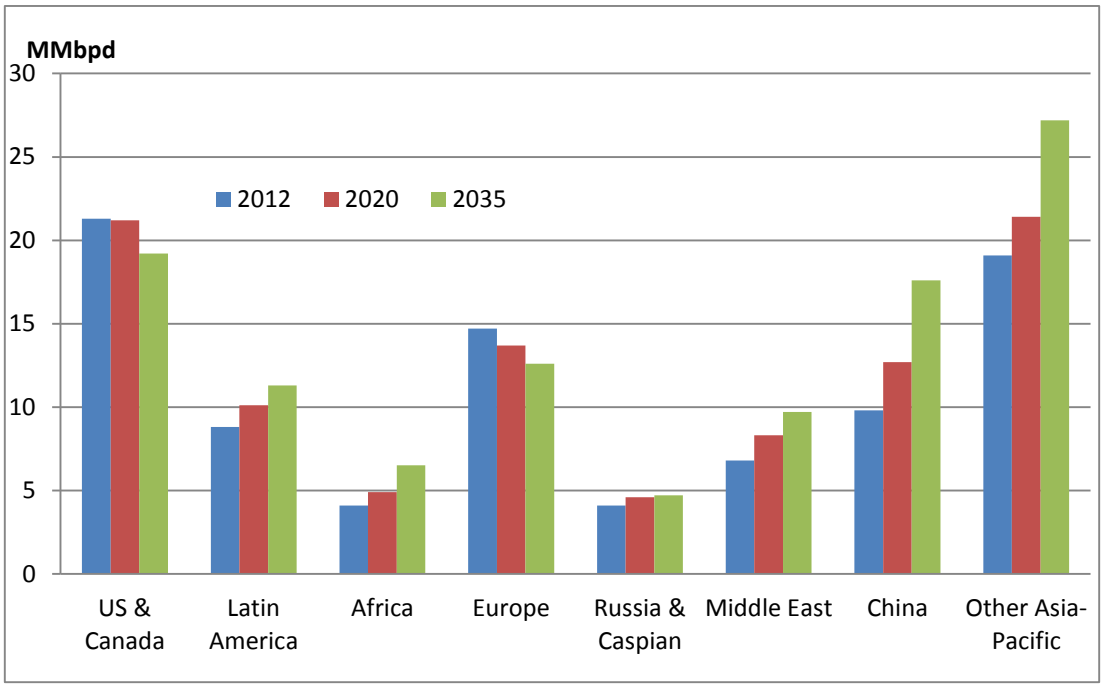
Refiners also face challenges in that the North American market has peaked in its product demand, meaning that an expansion of refining capacity to meet oil production would mean selling refined products to the export markets, specifically in developing nations of the Asia

[6] Even though the scale of refining capacity and proximity to tidewater could mean that the refineries do not necessarily need to be in close proximity to their markets.

[7] Hackett, D. et al. "Pacific Basin Heavy Oil Refining Capacity". School of Public Policy Research Papers. 2013. Accessed June 25th 2014 from http://www.eisourcebook.org/cms/Feb%202013/Pacific%20Basic%20Heavy%20Oil%20Refining%20Capacity.pdf

Pacific.[8] OPEC's World Oil Outlook for 2013 forecasts that most future demand growth will be for middle distillates and gasoline. Figure 1.3 depicts projected refined product demand by region.

Figure 1.3: Refined Product Demand Forecast*



*Products that make up the total product demand include ethane/LPG, naphtha, gasoline, jet fuel, kerosene, diesel, gasoil, residual fuel, and other products.
Source: OPEC World Oil Outlook 2013

The mix of products differs from region to region. Table 1.1 shows the percentage shares of refined products by region.

Table 1.1: 2013 Refined Product Share of Mix by Selected Regions (%)

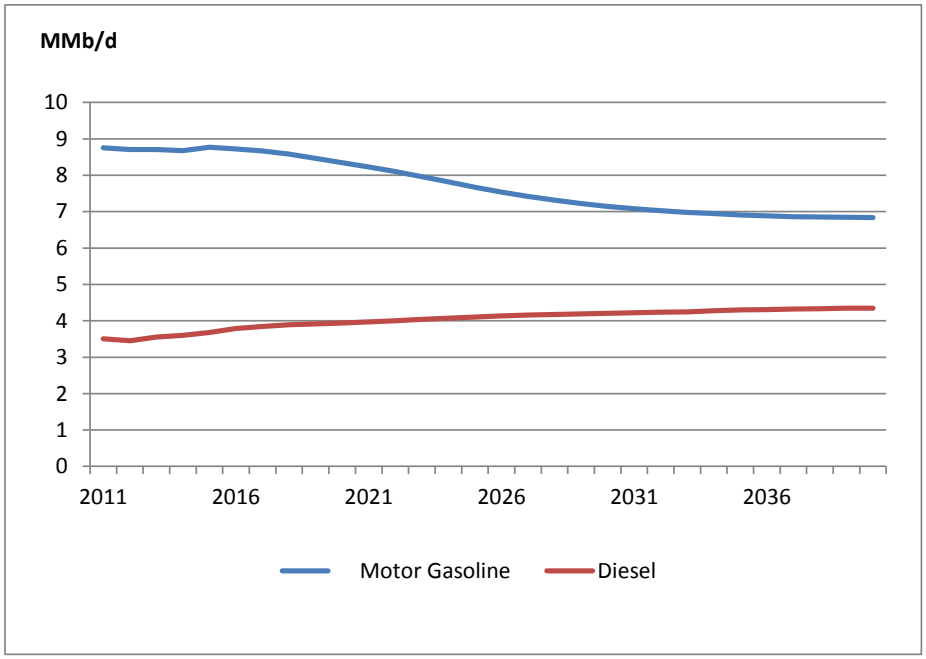
Region	Light Distillates (LPG, gasoline, naphtha)	Middle Distillates (kerosene, diesel)	Fuel Oil (marine bunkers, crude oil as fuel)	Other (refinery gases, residuals, etc.)
North America	46.0	28.0	2.5	23.5
S & Cent. America	30.1	40.0	10.0	19.9
Europe	20.9	52.8	6.8	19.5
Middle East	22.5	31.2	24.7	21.6
Africa	24.1	47.8	12.2	15.9
Asia Pacific	31.5	35.5	10.7	22.3
China	30.9	37.2	7.0	24.9
Japan	36.6	29.7	14.0	19.7
World	32.2	36.7	9.2	21.9

Source: BP Statistical Review 2014

[8] IHS CERA. "Extracting Economic Value from the Canadian Oil Sands: Upgrading and Refining in Alberta (or Not)?" March 2013.

Historically, gasoline has been the dominant product for the North American market, but as cars improve energy efficiencies, the share of gasoline is expected to decline. Over time, diesel demand is expected to increase due to more diesel powered vehicles, and changes in International Maritime Organization (IMO) regulations for ships.[9,10] For refiners this means converting fluid catalytic cracking units to gas oil/diesel hydrocracking units. The US Energy Information Administration (US/EIA) forecasts a decline in gasoline production and an increase in diesel over time. This is depicted in Figure 1.4.

Figure 1.4: US Refinery Gasoline and Diesel Production Forecast



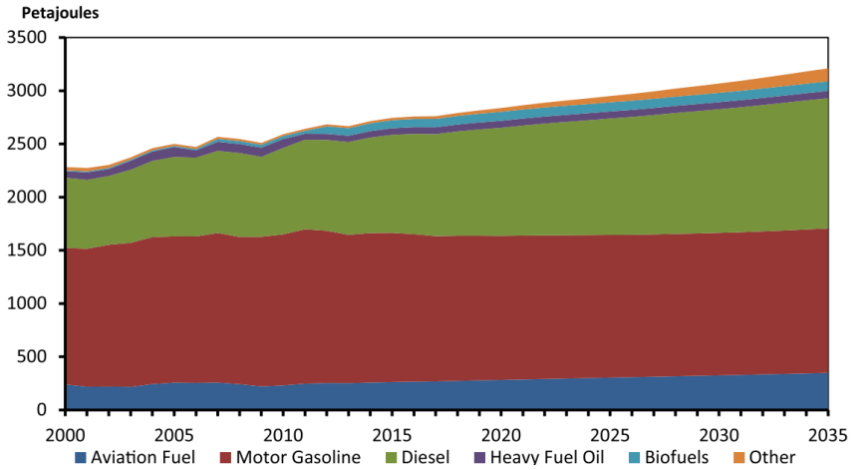
Source: US/EIA, Annual Energy Outlook (AEO), 2014

Within Canada, the National Energy Board's (NEB's) 2013 energy outlook states that in 2011 passenger transportation made up a majority portion of the demand, but in 2020 freight takes up the largest share. Since gasoline is prevalent in passenger demand, but diesel is more widely utilized for freight demand, diesel consumption is expected to increase by 1.6 percent per year (Figure 1.5).

[9] OPEC. "World Oil Outlook 2013". Accessed July 2nd from http://www.opec.org/opec_web/static_files_project/media/downloads/publications/WOO_2013.pdf

[10] Due to the California Local Air Emissions Regulations, and the International Maritime Organization, ships that are within 24 nautical miles off the Californian coastline can only have their auxiliary diesel engine operating on gas oil, or diesel, with a sulphur content less than 0.5%. Accessed July 2nd 2014 from http://shipsbusiness.com/sulphur-oxides-emissions.html

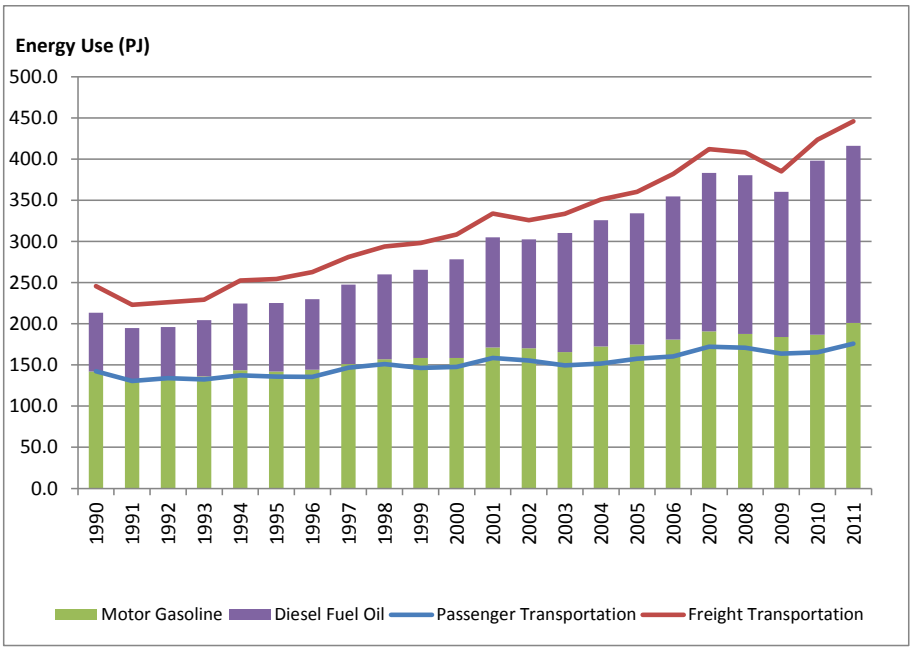
Figure 1.5: Canadian Transportation Sector Demand Forecast



Source: NEB, "Canada' Energy Future 2013: Energy Supply and Demand Projections to 2035", November 2013

Alberta has been experiencing increasing diesel consumption due to the expansion of truck fleets to meet transportation requirements for energy products. Alberta Transportation reports that trucks are responsible for moving 60 percent of freight within the province, and that heavy truck registration has increased by 46 percent in the last 10 years.[11] Figure 1.6 depicts the energy use from the increasing role of freight transportation in Alberta.

Figure 1.6: Freight and Passenger Fleet Energy Use



Source: Natural Resources Canada (NRCan), Office of Energy Efficiency

[11] Transportation: About the Industry. http://www.albertacanada.com/business/industries/lma-about-the-industry.aspx. Accessed July 7th 2014.

The planned North West Upgrader in Alberta is slated to meet a diesel shortfall, and will be discussed in more detail later in the report; however, even at its capacity of 150,000 barrels per day (BPD) after three phases, it is a small refinery by North American standards. The small size is also indicative of how small the North American market is to support future expansion for domestic use.

Oil Value Chain

The question of whether to upgrade or refine oil in Western Canada is touted by proponents of refining as keeping manufacturing jobs within Canada, and is criticized by its opponents as being uneconomic because the price differential of synthetic crude oil, or refined products, to heavy oil is not sufficiently large enough to justify the cost of building the refinery. Both sides of the argument come from different stakeholder concerns and both see different benefits as value: for proponents it is keeping more employment and economic activity in Canada, and for opponents it is the lack of a good return on investment over other capital expenditures.

In 2006, the Alberta government had stated a preference for upgrading more bitumen in the province which would bring more high-paying jobs into the province, and established the bitumen royalty-in-kind program (BRIK) whose objectives were as follows:[12]

1) Foster value-added oil sands development by using bitumen royalties for the development of upgrading facilities;
2) Enhance the transparency and liquidity of the bitumen market to help the government get better value for the bitumen it sells;
3) Diversify the gains and risks by being able to sell both synthetic crude oil (SCO) and bitumen.

Currently, the desire to incorporate value-added components is showcased in the government's involvement with the North West Upgrader. However, the Alberta government is not alone in wanting to keep more of the value chain jobs within Canada. The federal New Democratic Party (NDP) also believes that processing bitumen in Canada would bring about more jobs and add value to Canada.[13] A 2012 poll conducted on behalf of the Canadian Chamber of Commerce of approximately 2,000 Canadian residents stated that 80 percent of Canadians would prefer to domestically refine oil in Canada before importing oil from other countries.[14] A more recent poll conducted by the Alberta Industrial Heartland reports that 90 percent of Albertans support a

[12] Standing Committee on Alberta's Economic Future. "Review of the BRIK (Bitumen Royalty-in-Kind) Program". May 2013. Accessed July 2nd 2014 from http://albertaenergyplus.ca/wp-content/uploads/2013/05/AEF-Report-BRIK_web-version.pdf

[13] Globe and Mail. "Keystone 'not in Canada's best interests,' NDP says". November 2013. Accessed on November 13, 2014. http://www.theglobeandmail.com/news/politics/keystone-not-in-canadas-best-interests-ndp-says/article15324816/

[14] McDermott, V. "Majority of Canadians support increased oil production: poll". Fort McMurray Today. May 3rd 2012. Accessed July 2nd 2014 from http://www.fortmcmurraytoday.com/2012/05/03/majority-of-canadians-support-increased-oil-production-poll

value-added strategy.[15] David Black, the proponent behind the Kitimat refinery project, believes that there are also environmental benefits to refining in Canada in the form of reduced risk from oil spills. Another argument is that in Canada the refinery would utilize state-of-the-art carbon capture and sulphur reduction technologies and thus the life-cycle emissions of a made-in-Canada refinery would be lower than elsewhere.

Despite some of the benefits there are still uncertainties including but not limited to the risk of capital overruns and rising labour costs combined with uncertain future differentials; thus, some companies view greenfield upgrading and refining in Canada as a risky venture compared to brownfield but underutilized facilities capable of processing heavy crude in Asia and the US.[16]

Phillip Cross in "Extracting the Most Value from Canada's Petroleum" explains which sector adds the most value-added.[17] The following table based on Statistics Canada's input/output table from the report is copied below.

Table 1.2: Value-Added and Gross Output for Oil-Related Industries (2009 million dollars)

Industry	Gross Output	Value-Added	Value-Added Share
Services to oil and gas	14,345	6,427	44.8%
Engineering construction oil and gas	25,602	8,636	33.7%
Crude extraction	96,374	64,174	66.6%
Pipelines	3,278	2,374	72.4%
Refining	63,560	8,614	13.6%
Petroleum wholesale	5,737	3,094	53.9%
Gas stations	7,130	4,399	61.7%

Source: Cross, P. & Statistics Canada 2009 Input/Output Tables

In Cross's report there is no disaggregation of where value-added comes from but the key message is that value-added refining on top of the crude that refineries would purchase adds

[15] Pratt, S. "Majority of Albertans support bitumen upgrading incentives: poll". July 2nd 2014. Accessed July 3rd 2014 from http://www.calgaryherald.com/news/edmonton/Majority+Albertans+support+bitumen+upgrading+incentives/9994957/story.html

[16] Hoekstra, G. "Industry skeptical about shipping refined oil to Asia: Economics challenging, and Asia looking for raw bitumen, analysts say". Vancouver Sun. April 23rd 2014. Accessed on June 25th 2014 from http://www.vancouversun.com/business/Industry+skeptical+about+shipping+refined+Asia/9768801/story.html

[17] Cross, P. "Extracting the Most Value from Canada's Petroleum". Macdonald-Laurier Institute Publication. 2013

13.6 percent to the total value of output.[18] Most of the value-added is within the crude oil extraction itself and this forms the basis of the argument by opponents of refining in Canada. Essentially, for a given investment a significant amount of jobs will naturally be created by oil production that would be high-paying. This results in the benefit of a high demand for labour and material inputs. It also follows that this demand induces substantial purchases of specialized goods and services that would require high levels of education and training. Refinery investments are long-term decisions and therefore the jobs related to refineries would presumably be more long-term stable jobs. Retail would be the last portion that could add significant value-added but given that there is no strong forecasted demand in North America it is unlikely there will be significant expansion of retail capacity. Investing in a refinery would still add additional jobs but the question becomes whether these jobs are better than other jobs that could have been created from the same investment in other sectors or regions. If refining adds less value than oil extraction, and given the current low unemployment rate in Alberta, constructing more refineries might add pressure to an already constrained labour market, increase labour cost inflation and/or could lead to lower oil sands production. In turn, this would raise bitumen prices (assuming heavy oil demand stays the same), which makes refining less viable due to narrow light-heavy differential. Given the difficulties in assessing this job creation benefit, and the diversity of views regarding the costs and benefits of refining, it is not surprising that there is no clear consensus on the merits of refining in North America.

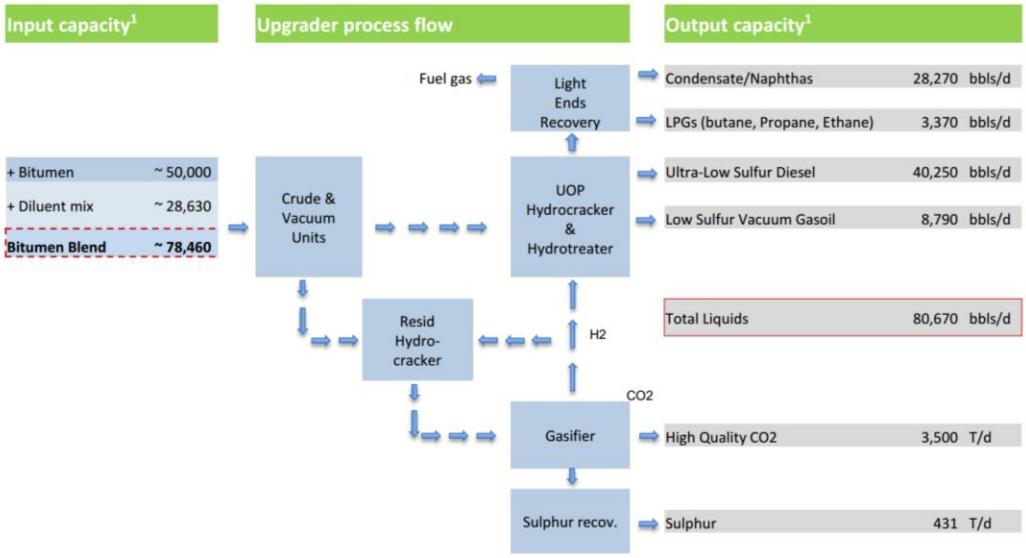
Finally, there is uncertainty over future greenhouse gas and climate policies in North America and around the world. Changes in direct emission costs from future greenhouse gas pricing may change the economics of a proposed refinery, depending on the anticipated return and the price set per tonne of carbon dioxide emitted.

North West Upgrader (North West Redwater Partnership)

Canada had not seen the construction of a major greenfield refinery in almost three decades until the $8.5 billion North West Upgrader (NWU) was brought forward by the North West Redwater Partnership (NWRP). Construction of the refinery will be done in three phases, each of 50,000 BPD capacity. The government will supply 75 percent of feedstock or 37,500 BPD of bitumen through the Bitumen Royalty-in-Kind (BRIK) program, with Canadian Natural Resources Limited (CNRL) supplying the remainder. The main products will be ultra-low sulphur diesel, naphtha, and diluent. The project will also capture carbon dioxide, some of which will be sold to Enhance Energy's Carbon Trunk Line for enhanced oil recovery (EOR) in existing conventional oil fields in central Alberta and the remainder will be sequestered. Figure 1.7 contains the flow diagram of the process:

[18] This result is an estimate. Most refining in Canada is done by vertically integrated companies and data for each of their North American Industry Classification System (NAICS) activities are not disaggregated. Statistics Canada disaggregates such data using proxies to arrive at their value-added. Hence, the value-added for the sector of petroleum refining might be underestimated as a result of Statistics Canada allocating all profit for vertically-integrated companies to their extraction activities. As a result, the input/output tables assess the value-added for the sector of petroleum refining as the sum of labour costs plus taxes paid by refineries.

Figure 1.7: Flow Diagram of North West Upgrader Process



Source: North West Upgrading Partnership[19]

This project has not been without controversy due to escalating costs that have required a complicated toll structure to be put in place. The agreement[20] established a cost-of-service contract with a 30-year term, of which the NWRP will be the processor, responsible for financing and constructing the refinery. Once the refinery is in operation, NWRP will charge a toll to recover the costs which will be paid by CNRL and the Alberta government. This toll would help the processor to recover their initial capital costs, repay any debts, and earn an acceptable rate of return on equity plus operating costs. In other words, the NWRP is entitled to recover the operating costs plus a return on capital, and a return of capital through a service toll. The cash proceeds from the sale of the products are placed into a trust fund administered by a third party. For a more detailed description of the original contract, see "The Standing Committee on Alberta's Economic Future: Report on the BRIK Program Review".[21]

Literature review of NWU's documents and CERI's internal evaluation of the costs and benefits of the NWU are illustrated in Table 1.3 below.

[19] Annual General Meeting. May 9th 2013. Accessed July 8th 2014 from http://www.northwestupgrading.com/sites/default/files/pdfs/nwu%20agm%20presentation%20may%209%202013.pdf
[20] http://www.energy.alberta.ca/Org/pdfs/BRIKagreement2Process.pdf
[21] http://albertaenergyplus.ca/wp-content/uploads/2013/05/AEF-Report-BRIK_web-version.pdf

Table 1.3: Costs and Benefits of the North West Upgrader

Cost	Benefit
- High capital cost that no longer possesses a cap on final cost requiring an open-ended sub-ordinated debt; - Uncertain light/heavy oil differential in future combined with a return to the company at potential expense to the government and by extension society; - Strain on labour market that faces a low-unemployment rate.	- Production of high quality diesel and condensate close to the area of demand; - Compression of high quality CO_2 that will allow further EOR recovery of light oil plus reduce overall well-to-tank emissions; - Net restoration of wetlands in addition to lower land-use impact due to high-intensity development.

Source: CERI

The NWU will generate employment, however, in a labour-constrained market with high productivity of upstream activities the typical benefits of employment, GDP, and income taxes are expected to be similar for this project compared to other investments. The societal benefit is mostly tied to reduced emissions of greenhouse gases and criteria air contaminants[22] as well as lower land-use impact.

[22] Criteria air contaminants (CACs) are primary constituents of air pollution that lead to common, broad-scale air quality issues including smog and acid rain. The CACs include sulphur oxides, nitrogen oxides, particulate matter, volatile organic compounds, carbon monoxide, and ammonia. For further information, see http://www.ec.gc.ca/Air/default.asp?lang=En&n=7C43740B-1

Chapter 2: Modelling Methodology

Methodology and Analysis

The increased economic activity from investment in the oil and gas sector has benefits such as growth in employment and wages. However, infrastructure may not always be able to keep up with an influx of people migrating into a region to take advantage of lucrative oil and gas jobs. As a result there can be housing shortages, overcrowding in hospitals, and decreased municipal services. Even though investment in the oil and gas sector leads to increased wages over all sectors, many businesses still need to reduce hours as a result of staffing shortages. Also, oil and gas sector development is considered to have significant environmental impact and of particular concern are the increasing greenhouse gas (GHG) emissions from upstream unconventional oil production.

Environmental impacts are additional societal costs from a project such as a refinery. For example, GHGs, a major contributor to climate change, can impose environmental and social costs by affecting human and ecosystem health, causing additional costs due to climate change mitigation, and reducing economic output. Emissions of criteria air contaminants, such as sulphur dioxide, nitrogen oxides, and particulate matter, can impose costs through environmental damage and human health impacts. In addition to long-term climate change effects, social costs may arise from other environmental impacts, including but not limited to land use change, water use, and impacts on natural habitat that reduces the quality of ecosystems. Some of these costs may ultimately have a major impact on the overall cost-benefit balance of a project. Since the upsides and downsides of a particular investment cannot be adequately addressed by traditional models like cash flow analysis or economic models such as input-output analysis, a more holistic approach is required. CERI has chosen to undertake a cost-benefit analysis (CBA) that includes both economic and environmental costs and benefits to determine whether a project is a net benefit or a net cost to society.

Cost-Benefit Analysis

Cost-benefit analysis is a framework that identifies, quantifies and compares the costs and benefits of a proposed policy or mode of action. The formal foundation of a CBA is that benefits increase human well-being and costs reduce it. For a project to qualify as a net benefit, the social benefits, be it job creation, improved health, etc., must outweigh the social costs (i.e., compensation for increased air pollution). CBA has been a cause for debate because the benefits may be non-monetary such as improved water quality, or habitat protection for species preservation, but the costs are usually reflected as a higher value for a product as measured in dollars. As a result the market and economic effects can be easily quantified in dollars but non-market effects can only be indirectly inferred by assigning a value to them. One of the challenges of CBA is determining the relative merits of one action compared to others and thus one cannot avoid some bias due to the different perceptions of what is valuable. However, while CBA is far from perfect it does follow a robust framework on evaluating the merits of different action and ranking them in relation to each other. Thus the rationale for using CBA is to illustrate the gains

and losses of a given action in a broader societal context, and to look at who receive the benefits and who incur the costs. The societal approach avoids solely restricting the impacts to reflect a single group of stakeholders' interests.

In a very simplistic sense, conducting a CBA is done in a series of stages. The first stage is to ask the questions "what potential costs and benefits exist?" and "what alternatives are there?" This stage is a catalogue of alternative scenarios and of the potential impacts of the project. The next is determining the time horizon over which the costs and benefits are counted and this typically involves discounting of future impacts into present terms. The final step involves identifying the when and how costs and benefits are applied.[1] Projects that have a positive net present value are deemed to be more beneficial to society. Since some of the values are uncertain it is important to conduct a sensitivity analysis to see how the results change. Formally, the analysis entails solving the following equation:

$$NSB = \sum_{t=0}^{n} \frac{R_t - C_t}{(1+r)^t}$$

Where *NSB* is net social benefit, *R* is revenues generated from sales of the products, *C* is the cost of refining, *r* is the discount rate, *t* is the year, and *n* is the number of years in the project. Environmental impacts are treated as costs. Social externalities such as health impacts were considered to be a zero impact in this analysis given the industrial site location of the greenfield refinery. Another assumption is that there will be no legacy benefits or costs occurring at the end of a project's life. All the monetary values are in real 2013 Canadian dollars unless stated otherwise. The CBA analysis is conducted following generic steps of CBA as described in "Benefit-Cost Analysis Guide".[2]

CBA Scope

CERI has completed a CBA of refining bitumen in Alberta. *The representative project to be used as a proxy to a greenfield commercial refinery is the North West Upgrader; the elements such as capital costs and mass balances are only used as a reference and by no means is this a cost-benefit analysis of the North West Upgrader*. Only the first phase of the NWU will be considered at 50,000 BPD input capacity. Other types of refining processes that produce different slates of products, such as gasoline and jet fuel were not considered within the scope of this study given the forecast of demand for products in Alberta suggests an increase in diesel and a decrease or flat growth of other products.

The end result is to compare the costs and benefits of refining in Alberta and run a sensitivity analysis by varying important components, such as a presence of a carbon capture and storage (CCS) unit and diesel prices. The CBA is done assuming funds are commercially acquired.

[1] Peace, D., G. Atkinson, S. Mourato. Cost-Benefit Analysis and the Environment. OECD Publishing. 2006
[2] Treasury Board of Canadian Secretariat. Benefit-Cost Analysis Guide. Ottawa. 1998

Benefits

Revenues

The revenue stream is calculated by first developing forecasts of refined product output and product prices and secondly, multiplying these together. We assume an average-over-the-project-life 93 percent utilization rate and 80,670 BPD output. The project starts construction in 2014 and becomes operational in 2017, and will have a 50-year project life. We are assuming there will be no delays in the construction schedule and no additional costs incurred as a result, whereas in reality, expanded timeline of a large-scale project might create significant delays which would increase costs of the project.

Given that the output comes in various refined products, the prices used to estimate the project's revenue streams are also dependent on what product revenue is being estimated. Half of the 80,670 BPD output will be low-sulphur diesel which is assumed to be consumed in domestic markets and priced regionally, given the refinery's inland location, small capacity, and increasing demand for diesel in Alberta. To estimate revenues from sales of diesel, CERI uses the Alberta diesel price forecast sourced from the most recent National Energy Board's (NEB) energy forecast report.[3] As the NEB's forecast is only to 2035, extrapolation was required to extend the price forecast to the end of the project life – to 2066 by applying an average rate of growth from 2014 to 2035. The prices were also translated from CDN$/GJ to CDN$/bbl. Other products' price forecasts were not readily available and hence were priced off the WTI and Henry Hub prices' forecasts, which were sourced from the latest US/EIA's Annual Energy Outlook (AEO) 2014. Since the US/EIA's forecast ends in 2040, average growth rates were applied to extend the forecast to 2066. Also, because the price forecast is expressed in US dollars, an exchange rate of US$0.95 (based on recent historical values) was applied to translate the currency to Canadian. The price ratios of other products to WTI oil and Henry Hub gas prices are calculated based on the recent historical price data. Table 2.1 shows these ratios for each individual product that will be produced at the refinery.

Table 2.1: Historical Price Ratios

Product Price	Average (2002-2014) Price Ratio
AECO Gas (% of HH)	87%
AB Ethane (% of AECO gas)	147%
Propane (% of WTI)	55%
Butane (% of WTI)	78%
Diluent (% over WTI)	5%
Vacuum Gasoil	70%*(Price of Gasoline) + 30%*(Price of Diesel)

Source: CERI

Another source of revenue will be the sales of captured carbon dioxide (CO_2), since the refinery will be equipped with a carbon capturing unit and anything that is not stored or emitted will be

[3] NEB. "Canada's Energy Future 2013: Energy Supply and Demand Projections to 2035", November 2013.

sold to oil producers for enhanced oil recovery (EOR) extraction. The value of CO_2 to EOR producers is unclear and how much they are willing to pay to NWU for the sale of CO_2 is not known. Hence, to calculate the revenue from the CO_2 sales, CERI used the current carbon levy of $15/tonne of CO_2, as prescribed in the Alberta government's "Climate Change and Emissions Management Amendment Act, 2007".

Employment Benefits

From the Table E.11.3.1.1 of the Redwater's original Environmental Impact Assessment's (EIA)[4] Appendix E, the construction work-force person-hours are estimated and presented in Table 2.2.

Table 2.2: Construction Person-Hours

Trade	Approximate '000 person-hours*	Percent %
Pipefitter/Welder	11,900	31
Labourer	6,100	16
Electrician	4,600	12
Carpenter/Scaffolder	3,500	9
Operating Engineer	3,500	9
Iron Worker	3,500	9
Boiler Maker	1,500	4
Teamster	1,500	4
Cement Mason	800	2
Millwright	500	1
Painter	500	1
Insulator	500	1
Total	38,400	

*The estimates in the EIA are over a 9-year construction period for all three phases. CERI's scope only encompasses the first phase.
Source: Redwater Partnership Sturgeon Refinery Environmental Impact Assessment.

It is expected that around 225 people will be employed during the first phase of development.

The per capita income for Sturgeon County, where the NWU will be located was estimated to be $43,446 for 2011 and was projected to reach $47,614 for 2013.[5] Table 2.3 summarizes available information on wages and salaries from Alberta's wage and salary survey. Most jobs that will be generated during the construction period pay higher than an average salary in the County. When all occupations are weighted for their respective person-hours the average salary becomes

[4] North West Upgrader Project. 2006. Environmental Impact Assessment. Appendix E.11 – Socio-economic assessment and land-use.
[5] Accessed July 21st 2014 from http://www.lifeintheheartland.com/documents/9-SturgeonCounty.pdf

$81,663 which is about $34,049 higher than the county average. The average income in Canada reported for the year 2013 was around $47,358 and the average income in Alberta was $57,616[6].

Table 2.3: Average Annual Wages and Salaries in Alberta for 2013

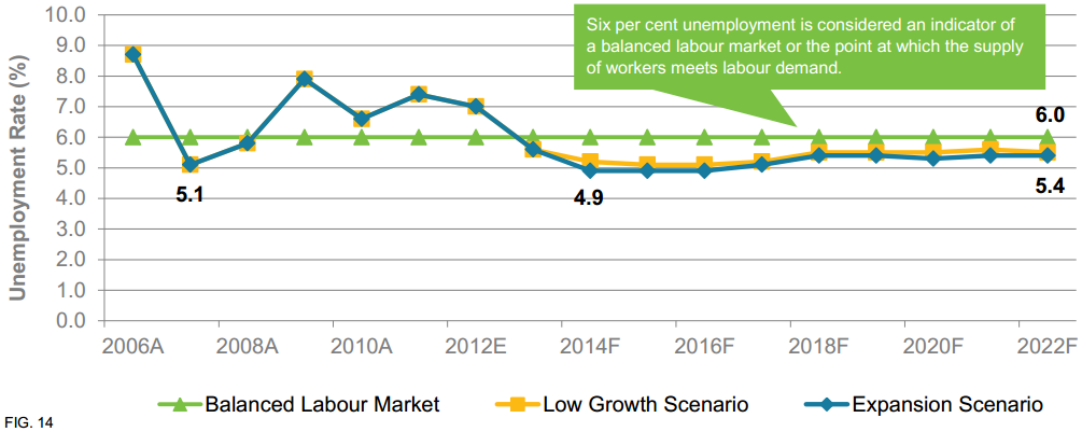
Trade	2013 Average Wage and Salary in Alberta ($)
Pipefitter/Welder[7]	100,099
Labourer[8]	41,499
Electrician[9]	102,311
Carpenter/Scaffolder[10]	72,190
Operating Engineer[11]	103,195
Iron Worker[12]	63,507
Boiler Maker[13]	67,689
Teamster[14]	74,330
Cement Mason[15]	59,558
Millwright[16]	86,638
Painter[17]	72,465
Insulator[18]	89,143

Source: Alberta Government[19]

The Petroleum Human Resources Council of Canada (PHRCC) predicts that within the petroleum sector in Canada there will be skilled labour shortages well into 2022. Alberta, Saskatchewan, and BC are expected to have even lower unemployment rates because of expanding non-conventional production and potential increases in LNG export capacity.[20] Figure 2.1 showcases how the unemployment rate is projected until 2022.

[6] CANSIM Table 281-0027
[7] Welders and Related Machine Operators – Oil and Gas Extraction
[8] Labourers Chemical Products Processing and Utilities - Construction
[9] Electrician – Oil and Gas Extraction
[10] Carpenter - Construction
[11] Stationary Engineer and Auxiliary Equipment Operators – Oil and Gas Extraction
[12] Ironworker - Construction
[13] Boilermakers – Oil and Gas Extraction
[14] Truck Drivers – Oil and Gas Extraction
[15] Concrete Finisher - Construction
[16] Construction Millwrights and Industrial Mechanics (Except Textile) – Oil and Gas Extraction
[17] Assumed Industrial Painter - Construction
[18] Insulators – Oil and Gas Extraction
[19] Alberta Government. 2013 Wage and Survey Information. Accessed July 16th 2014 from http://occinfo.alis.alberta.ca/occinfopreview/info/browse-wages.html
[20] Petroleum Human Resources Council of Canada. May 2013. The Decade Ahead: Labour Market Outlook to 2022 for Canada's Oil and Gas Industry. Accessed July 16th 2014 from http://www.iecbc.ca/sites/default/files/Enform%20Petroleum%20Labour%20Market%20Information%20canada_labour_market_outlook_to_2022_report_may_2013.pdf

Figure 2.1: PHRCC Labour Supply Gap Forecast



Source: PHRCC

The subject of employment has been controversial as governments prefer to add employment creation on the benefits side. However, in some cases this is not a legitimate procedure as it involves the risk of double-counting with alternatives. General equilibrium models such as Input-Output (I/O) have a snap shot of the economy and any divergences from this reality reflect existing uncertainties within the I/O model. Thus, the creation of employment is significant if there is high unemployment, or if one alternative generates meaningful spillover effects.

At low unemployment levels a typical CBA will assume that labour will "clear" the market. So any employment benefit that is derived from this investment involves people that could easily find employment elsewhere for a similar wage. In the case of a value-added project versus investment in the upstream sector the employment benefits are negligible as the wages are similar and it is very likely that most people would be employed elsewhere. Since the unemployment rate is very low, it is unlikely that there are a high number of people who would benefit from the higher income of employment in the project versus unemployment, nor would it affect the overall capital cost of the project significantly. The only people who could possibly benefit are those who migrate from other provinces where the wages are lower, but this is also offset by the higher living costs in Alberta as well as the additional infrastructure costs that would be incurred to house these people. As a result CERI concludes that employment is unlikely to differ between investments of 8.5 billion in the upstream industry versus 8.5 billion for the refinery and thus are neither benefits nor costs. If the value-added investment is made outside of Canada it is still considered to be insignificant on employment given the low unemployment levels in Alberta and the high likelihood of these people being employed regardless.

Costs

Capital and Operating Costs

The capital and operating costs of a hypothetical greenfield commercial refinery were based on the most recent estimates available for building and operating a refinery in Alberta – the North West Upgrader. Table 2.4 shows the components of capital cost in more detail and presents

annual operating costs at the bottom of the table. The proponents' initial capital costs are estimated to be $8.5 billion for Phase 1 development. The total operating costs amount to $164 million per year.[21]

Table 2.4 Capital and Operating Cost Estimates

Component	Estimated Cost (million $CDN)
Capital Spent to Date (Regulatory, Engineering, Initial Construction)	1,500
Gasifier Unit	799
Sulphur Recovery Unit and Light Ends Recovery Unit Modularization	580
Utilities – Refinery and Carbon Compression	500
Electrical	140
Crude Atmospheric Unit and Vacuum Atmospheric Unit	332-547
Hydrocracker-Hydrotreater	411-547
Resid Hydrocracker	2,731
Engineering and Procurement Tank Farm	130
Bitumen Storage Tanks	55
Booster and Main Compression	61
Other Expenses	884-1,233
Annual Operating Cost	164

*Totals may not add due to rounding
Source: Various sources based mostly on known contracts and estimated from other refineries recently constructed around the world.

The capital cost estimate for the Gasifier Unit includes the carbon capture technology, NWR Rectisol® unit, which co-produces H_2, CO_2 and acid gas product streams as part of a highly integrated design complex in an industrial greenfield setting. The capital cost for this technology is $305 million (in 2007 dollars) and will be deducted from the Gasifier Unit as part of one of the sensitivity options to run a refinery without the carbon capture option.

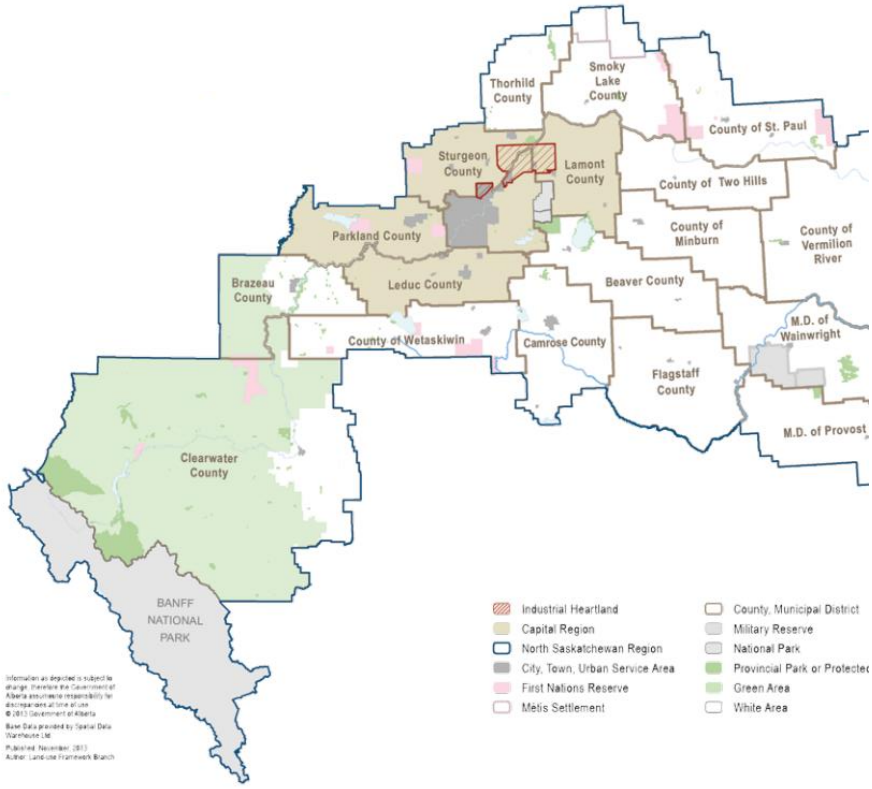
To finance the project, CERI assumes that the total capital investment will be met through two sources of financing – similar to other large-scale industrial development, 40 percent of capital will be borrowed at the long-term bond rate of 5.5 percent (real) for a 30-year term and the rest of capital, 60 percent of $8.5 billion will be coming from equity. This differs from the NWU's financing, where 80 percent is debt and only 20 percent is equity because it is assumed that this is a commercial stand-alone project without the support of public funds.

[21] The operating costs were not directly presented in the NWU's application, but instead were back-calculated by CERI from the toll structure.

Land Impacts

The greenfield refinery is assumed to be built in the industrial heartland of Alberta. According to the North Saskatchewan land use profile the heartland covers 582 square kilometres and is home to over 40 companies. It contains petrochemical complexes, refineries and upgraders along with rail lines, roads, various types of pipelines, and processing facilities around the City of Fort Saskatchewan, and the Lamont, Strathcona and Sturgeon counties. Figure 2.2 shows the region counties and land-uses.

Figure 2.2: North Saskatchewan Land Use Region



Source: Alberta Government

The complex itself is expected to take 235 Ha out of agricultural land-use and convert it into heavy industrial use. The NWU's EIA maps the potentially affected land and its utilization for their land study area which includes the refinery complex itself plus the adjacent lands. Table 2.5 is reproduced from the Table E.5.2.1.1 "Land Units in the Local Study Area" of Appendix E.5 of the original EIA.[22]

[22] North West Upgrader Project. 2006. Environmental Impact Assessment – Appendix E.5 Vegetation

Table 2.5: Land Unit Mapping of Upgrader Project

Land Unit	Area (ha)	Area (% of LSA)
Trembling aspen Woodland Alliance	7.8	2.7
Trembling aspen – Balsam poplar Woodland Alliance	21.9	7.7
Willow spp. Shrub land Alliance[23]	12.5	4.4
Open Water and Willow spp. Shrub land Alliance	10.9	3.6
Cropland	223.0	77.9
Pasture	2.6	0.9
Disturbed Land	7.9	2.8
Total	286	100

Source: Redwater Partnership Sturgeon Refinery Environmental Impact Assessment

Since the greenfield refinery would be located within the Sturgeon Industrial Heartland there would be minimal impact to land-use conversion. The trembling aspen Woodland Alliance and trembling aspen – Balsam poplar Woodland Alliance, Willow spp. Shrub land Alliance, and Open Water and Willow spp. Shrub land Alliance are considered to potentially have wetlands. To generate the maximum effect the entire area of these land units is assumed to contain the wetland ecosystem. The NWU has an agreement to restore three times the area of wetlands lost during development. Furthermore, the project will set aside a portion of its lands to preserve part of the remaining wildlife corridors in the industrial heartland.[24] Table 2.6 summarizes the land costs. Disturbed lands are not included in this assessment.

Table 2.6: Land Approximate Costs for Sturgeon Refinery

Area	Low $/ha Value*	High $/ha Value	Area (ha)	Value Range (`000 $)
Wetland Ecosystem Services (initial loss)	1,250	6,351	53.1	66-337
Wetland Ecosystem Services (agreed gain)	1,250	6,351	159.3	198-1,011
Net Benefit			106.2	132-774

*Where needed, the ecosystem values have been inflated to 2013 dollars using the consumer price index.
Source: CERI, Sturgeon County Economic Development, Brander et al.[25]

For the CBA, CERI assumes that the land degradation will cost the project proponents similar costs as for the NWU and this is an incremental cost and hence needs to be included with the rest of the project costs. The wetland degradation cost is the median of the value range of the

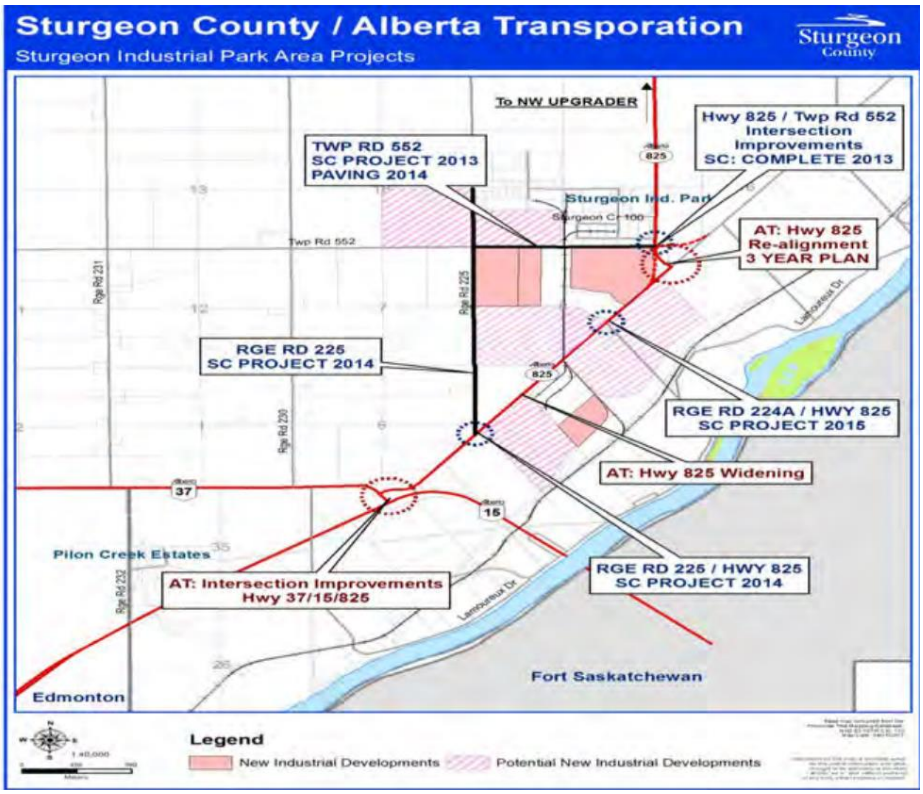
[23] Further descriptions are available on the EIA regulatory documents in the vegetation and baseline assessment report.
[24] From the North West Upgrading Partnership Website.
[25] Brander, L., Brouwer, R. & Wagtendonk. 2013. Economic valuation of regulating services provided by wetlands in agricultural landscapes: A meta-analysis. Ecological Engineering 56:89-96.

initial loss or $201.8 thousand. The restoration of wetland ecosystems, which is treated as a benefit, will be three times the area of wetlands lost during development, and the value of the restored land will range from $198 to $1,011 thousand. CERI assumes the median of that range.

Government Costs

Government costs can be disaggregated into two components. First, government conducts activities during a project's early life such as managing the environmental assessment process. However, costs incurred by the energy regulator are not considered because like employment the regulator would have costs associated with any $8.5 billion in energy development that cannot be quantified directly to a specific project and are considered to have happened regardless. Second, government makes investments in infrastructure such as highways and utilities. The cost attributable to a refinery can be estimated by sourcing the "Industrial Lands Assessment – Final Strategic Report for Sturgeon County" by Jonathan Eshun, where he summarizes some of the required infrastructure costs and potential tax revenue. Figure 2.3 is a map of the proposed infrastructure projects in the near-future; followed by Table 2.7 which shows the results of Eshun's report (only the sections for the Sturgeon Industrial Heartland have been included in this table).

Figure 2.3: Infrastructure Improvements Sturgeon County



Source: Sturgeon County Economic Development

Table 2.7: Sturgeon Industrial Heartland Statistics and Capital Cost Improvements

Total Park Size (Acre)	2,506
Vacant Developable Area (Acre)	2,335
Potential # of Lots	71
No. of existing tenants	24
Current Assessment	$43.4 million
Current Tax Revenue	$426,435
Potential Tax Revenue	$8,992,849
Transportation	$31,933,750
Water Distribution	$9,900,000
Sanitation	$7,851,250
Storm Water	$4,068,000

Source: Eshun[26]

The total estimated infrastructure improvements are around 54 million dollars and would be considered an incremental cost to government to establish the refinery.

Air Impacts

Assigning a social cost to greenhouse gas emissions is one way of trying to account for external costs incurred by society. Ideally, the social cost should incorporate all costs; for example, costs related to mitigating the effects of climate change, impacts on human and ecosystem health, and loss of economic activity. This approach reflected the generally accepted scientific opinion that anthropogenic carbon dioxide emissions are generating harmful climatic impacts, and that these impacts are not reflected in market values.

Estimates of social cost of greenhouse gas emissions, however, vary widely, and are highly dependent on how aggressive emissions reductions will be in the future and to what degree the costs for future generations (who, arguably, will bear the brunt of climate change-related costs) are discounted. One study found that, depending on whether carbon dioxide emissions were highly regulated or unconstrained, the social cost ranges from $4 per tonne of carbon dioxide to a high of $25,700 per tonne.[27]

Social costs of greenhouse gas emissions are obtained from a 2013 review of social cost studies.[28] The median social cost depends on the discount rate used for each study: the median social cost in 2010 $US for a 3 percent discount rate is $23 per tonne of carbon (or $6.27 per tonne of CO_2); for a 1 percent discount rate the median cost is $83 per ton of carbon ($23 per tonne of CO_2); and with no discount rate the median cost is $247 per tonne of carbon ($67 per tonne CO_2). In

[26] Eshun, J. 2011. Industrial Lands Assessment – Final: Strategic Report Sturgeon County. Accessed July 25th 2014 from http://www.startinsturgeon.ca/Portals/10/Documents/rpt_ed_industrial_lands_assessment_strategic_2011.pdf
[27] Howarth et al. (2014). Risk mitigation and the social cost of carbon. Global Environmental Change 24, 123 – 131.
[28] Tol (2013). Targets for global climate policy: an overview. Journal of Economic Dynamics & Control 37, 911 – 928.

comparison, the 2010 social cost of carbon adopted by the United States government is $32 per tonne of CO_2 emitted.[29]

Based on the emissions reported in the EIA for the North West Redwater Partnership Refinery, a 50,000 BPD project is anticipated to emit 85 Mt of CO_2 equivalents over a 50-year lifetime. With carbon capture of 1.2 Mt per year, which equates to taking approximately 300,000 light-duty vehicles off the road annually,[30] total emissions drop to 25 Mt over the project lifetime. For comparison, emissions from a high conversion refinery in PADD II, refining diluted bitumen was modeled to emit 55.3 kg of carbon dioxide per barrel,[31] for total 50-year emissions of 72 Mt of CO_2 at 50,000 barrels of bitumen processed per day, or 57.5 Mt of CO_2 for a PADD II refinery processing Nigeria's Bonny light crude (32.9 API) or 62.4 Mt of CO_2 for a PADD II refinery processing Saudi Arabia's Arab Medium crude (31.1 API).[32] Hence, emissions from a greenfield refinery with a carbon capture and dilbit feedstock would be considerably lower than for lighter crudes at a conventional high conversion refinery.

The social costs for total carbon emissions are calculated for the median carbon prices from Tol's 2013 review study for 0 percent, 1 percent, and 3 percent discount rates. The price per tonne of carbon increases by 2.3 percent annually based on the average growth rate in emissions cost reported in the study. Social costs are also calculated using the United States government estimated social costs (see Table 2.8). As the annual costs are only reported until the year 2050, the costs for later years are estimated based on linear extrapolation from the growth in carbon costs in years prior to 2050. Estimated social costs for greenhouse gas emissions range from $359 million to $3.9 billion (2013 $CDN) for the full project with carbon capture and storage, depending on the value assigned to the cost of CO_2 emissions. In comparison, the same project without CCS has total greenhouse gas emissions costs between $1.2 billion and $13.1 billion (2013 $CDN). For the CBA, the discount rate of 3 percent was chosen as the baseline and the other two rates are part of the sensitivity analysis.

[29] Interagency Working Group on Social Cost of Carbon, United States Government (2013). Technical Support Document: Technical Update of the Social Cost of Carbon for Regulatory Impact Analysis - Under Executive Order 12866. http://www.whitehouse.gov/sites/default/files/omb/assets/inforeg/technical-update-social-cost-of-carbon-for-regulator-impact-analysis.pdf

[30] Based on average emissions of about 3.9 t CO2 for light-duty gasoline and diesel cars and trucks in Canada in 2012, data from Environment Canada's 2012 National Inventory Report.

[31] Jacobs Consultancy (2009). Life cycle assessment comparison of North American and Imported Crudes. Prepared for Alberta Energy Research Institute.

[32] Ibid.

Table 2.8: Social Cost of Greenhouse Gas Emissions (million $CDN 2013)

	Tol (2013) – Discount Rate			US Government
	3%	1%	0%	
With CCS	359	1,296	3,855	1,824
Without CCS	1,221	4,408	13,117	6,206
High-conversion refinery*	1,041	3,757	11,180	5,290

*Estimated costs from a high conversion PADD II refinery are included for comparison.
Source: NWR EIA, Tol (2013), US Government (2013), Jacobs Consultancy (2009), CERI analysis.

For air pollutant emissions, including sulphur dioxide (SO_2), nitrogen oxides (NO_x) and fine particulate matter ($PM_{2.5}$), the cost of emissions are more difficult to ascertain, as these pollutants tend to have shorter lifetimes and more regional effects. Full social and environmental costs must therefore be done on a location-specific basis for greatest applicability, although this has not been performed for the Alberta Industrial Heartland region. In absence of a suitable analysis, an average value for rural United States is used, with SO_2 emissions set at $1,721 per tonne, NO_x emissions at $574 per tonne, and $PM_{2.5}$ emissions at $2,103 per tonne (converted to 2013 $CDN from 2000 $US).[33]

With reported emissions from the North West Redwater Partnership's EIA, the cost of emissions is estimated to be approximately $48 million in 2000 US dollars (see Table 2.9).

Table 2.9: Estimated Damage Costs of Air Pollutant Emissions

	Emissions (tonnes)	Estimated Cost (million $CDN 2013)
SO_2	12,410	21.4
NO_x	118,625	68.0
$PM_{2.5}$	913	1.9

Data sources: NWR EIA, Muller and Mendelsohn (2007), CERI Analysis.

Besides accounting for the social costs of emissions, the province also regulates the emissions of large-scale emitters. On July 1, 2007 the Alberta Government enacted their climate change plan, as detailed in Bill 3, "Climate Change and Emissions Management Amendment Act, 2007". Facilities with emissions greater than 100,000 tonnes of CO_2eq. per year are regulated to reduce emissions by 12 percent in carbon intensity per production unit. To help meet this 12 percent reduction target, the Alberta regulation allows a facility to comply in four ways:

1. Make facility changes to improve performance and lower emissions
2. Purchase Alberta-based carbon offsets
3. Pay $15-a-tonne into the Climate Change and Emissions Management Fund

[33] Muller and Mendelsohn (2007). Measuring the damages of air pollution in the United States. Journal of Environmental Economics and Management 54, 1 – 14.

4. Purchase/use emission performance credits generated in previous years or at other facilities.

While the province has yet to deploy a trading mechanism/market for carbon, CERI's model incorporates the $15.00/tonne tax for emissions over the 100,000 limit, increasing at an annual average inflation rate of 2.0 percent.

Water Impacts

The NWU plans to utilize fresh water from the North Saskatchewan River for process water with a required draw of 0.21 cubic metres per second (m^3/s). The environmental assessment materials report a median flow rate of 185 m^3/s for the North Saskatchewan River, with a 7Q10[34] flow of 65 m^3/s recorded in the City of Edmonton. Current licensed withdrawal rates between downtown Edmonton and the Alberta-Saskatchewan border total 23.23 m^3/s (although actual withdrawal rates are typically lower than the total volume licensed). The required draw rate is about 0.3 percent of low-flow conditions in the North Saskatchewan River, and is expected to have minimal effect on the overall flow of the river. Given the low impact, it is assumed that the environmental cost of the water withdrawal will be zero for the greenfield refinery.

Impacts on water quality with respect to acidifying emissions (nitrogen oxides and sulphur dioxide) were modeled in the NWU's environmental assessment. Overall, potential acid inputs to water bodies in close proximity to the proposed project would increase by 62.5 percent; regionally, the acid inputs increase by 17.4 percent. Despite the sizable increase in potential acidification, this represents 0.0023 percent of the annual acid-neutralizing capacity of the North Saskatchewan River, and on the order of 0.00025 percent of the acid-neutralizing capacity of nearby lakes in Elk Island National Park. Changes to water body pH is expected to be negligible over 25 years.

Water quality effects from un-ionized ammonia due to effluent discharge were modeled to increase from 0.009 mg/L to 0.017 mg/L at a point 1 km downstream from the point of discharge, modeled under low-flow conditions. This falls just below relevant water quality guidelines and is a small impact compared to ammonia from upstream effluent sources. Between ammonia concentrations and acidification, reported water quality effects are considered to be of negligible cost. Given negligible water impacts, these are not considered as significant incremental cost to the society and hence omitted from the CBA.

Other Assumptions

Other assumptions relating to the CBA need to be made. For ease of reference, they are presented in Table 2.10.

[34] The 7Q10 flow rate is the lowest 7-day average flow rate observed, on average, once every 10 years.

Table 2.10: Other Assumptions

Variable	Unit of Measurement	Assumed Value
Year of Currency	Year	2013
First Year of Production	Year	2017
Project Life	Years	50
Years of Financing	Years	30
Discount Rate (real)	%	15
Inflation Rate	%	2
Exchange Rate	USD$/CDN$	0.95
Financing Debt	%	40
Long-term Bond Rate	%	5.5
Discount Rate - Emissions	%	3
Carbon Levy	CDN$/T	15
Federal Tax Rate	%	15
Provincial Tax Rate	%	10

Source: CERI

The chosen discount rate of 15 percent is based on the assumption that the project proponent is not a vertically-integrated company and faces market entry challenges and risks[35] specific to remote markets such as Alberta. These risks translate to a discount rate that is above the traditional cost of capital.

The sensitivity analysis was performed by varying some key variables in the cost-benefit calculation. The variables of interest are the CCS unit, discount rate, oil prices, diesel prices, capital costs, operating costs, discount rates for the emissions social costs, and financing. Table 2.11 presents the assumptions regarding the degree of variance among these variables.

Table 2.11: Sensitivity Analysis

Variable	
CCS Unit	Yes/No
Discount Rate	+/- 2%
Oil Prices	+/- 20%
Diesel Prices	+/- 20%
Capital Costs	+/- 25%
Operating Costs	+/- 25%
Discount Rate for Emissions	0%/1%
Debt	+/- 10%

Source: CERI

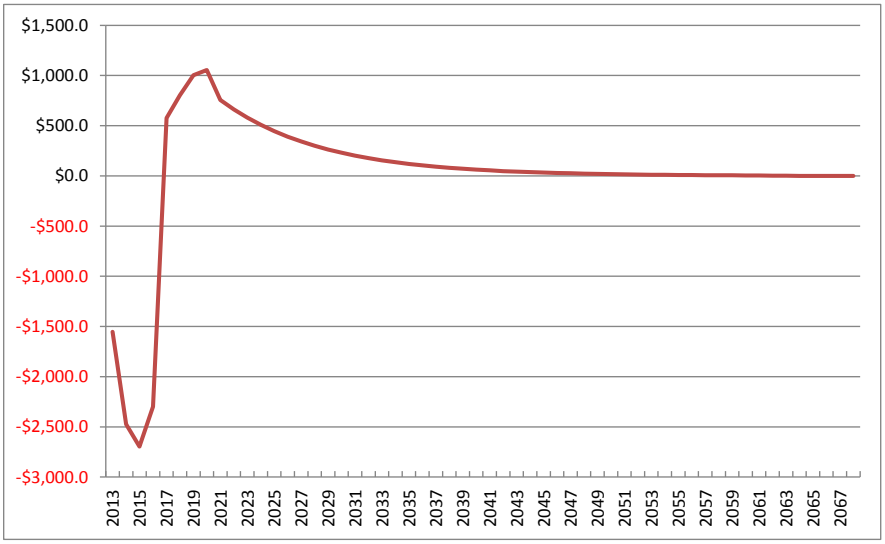
[35] The factors that contribute to a higher cost of capital in Canada can be found in the Bank of Canada paper. "Estimating the Cost of Equity for Canadian and U.S. Firm". 2007. http://www.bankofcanada.ca/wp-content/uploads/2010/06/zorn1.pdf. Accessed on December 10, 2014.

Chapter 3: CBA Results

This chapter presents the results of the cost-benefit analysis (CBA) and the sensitivity analysis. The steps involved were calculating the net present value of the project on an annual basis for the study period by summing benefits and costs for each year and then discounting this stream of values to arrive at a net present value (NPV). We used a rate of 15 percent, which is consistent with that in the private sector in the oil refining business.

The NPV of a greenfield refinery in Alberta with a carbon capture unit installed is a net benefit of almost $533 million.[36] The present value of the cash flow stream is presented in Figure 3.1.

Figure 3.1: Present Value of Cash Flow of the Project



Source: CERI

The discounted cash flow valuation method we used is subject to a variety of risk factors. The main risk factors include:

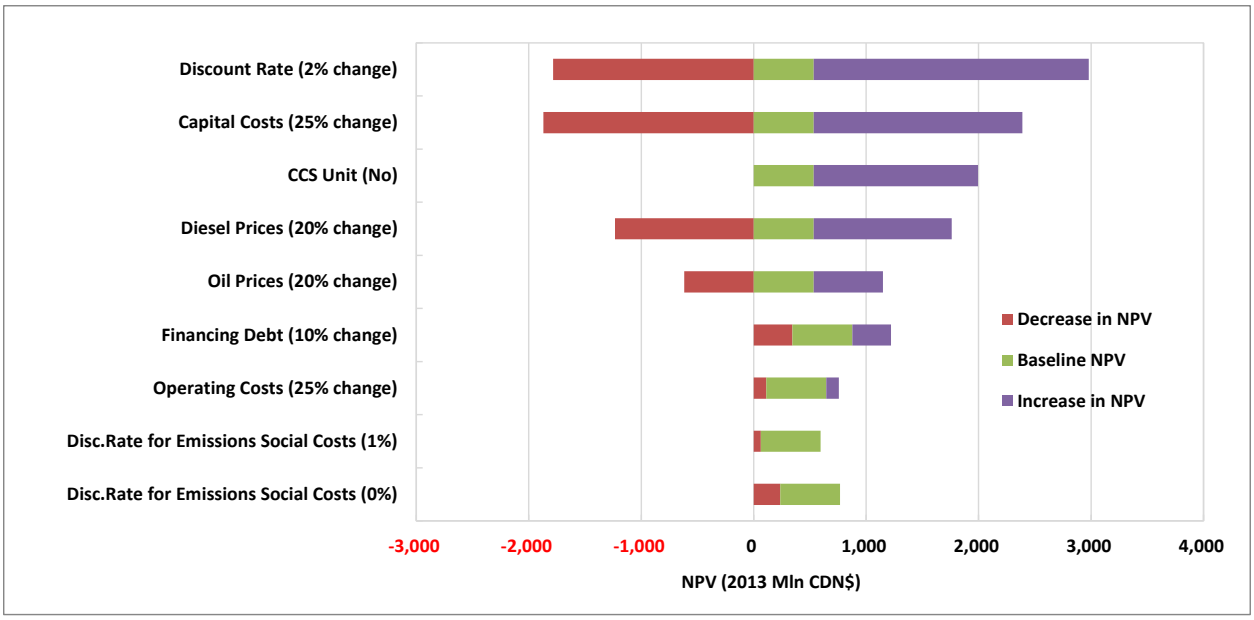
- *Macroeconomic and Microeconomic Conditions* – changes in the global and regional markets, such as prices for products, supply and demand dynamics, transportation costs, would affect the economics of refining;
- *Policy and Regulations* – government policy, intervention and regulation might impact the value of the project and the company itself; and
- *Environmental* – cumulative costs of complying with environmental regulations imposed on refineries by all levels of government have been rising and will have a significant impact on greenfield refineries.

[36] The NPV is $532.74 with an assumed 15% discount rate and a 50-year project life.

The last step in the CBA entails conducting sensitivity analysis to examine how alternative values for several parameters affect NPV. The economics of a refinery are complex and depend on many factors. Profits or losses result primarily from the difference between the cost of inputs and the price of outputs. In order to have a competitive edge, a business must make higher-value products using lower-cost inputs than competitors. In the oil refining business, the cost of inputs (crude oil) and the price of outputs (refined products) are both highly volatile, influenced by global, regional, and local supply and demand changes. In order to be profitable, refineries must optimize their production against a backdrop of changing environmental regulation, changing demand patterns and increased global competition among refiners. Hence, eight different parameters were chosen that would have a significant influence over the NPV of a project.

The results of the sensitivity analysis are presented in Figure 3.2. The Figure illustrates the change in the NPV by varying the parameter. The baseline NPV of the project (green bar) is positive $533 million and depending on the variable that is changed, the NPV will change as well. For example, if a carbon capture unit is omitted from the construction of the refinery, the capital cost will decrease, the emissions will increase, and NPV will increase by $1,461 million, bringing the NPV to almost $2.0 billion. Removing the CCS unit makes the refinery even more economic because of the substantial increase in NPV despite the fact that the refinery will have higher emissions and therefore incur higher social and carbon costs. This result suggests that carbon capture units are not economically desirable, and there would need to be much larger penalties on emissions to justify the placement of carbon capture on refinery units.

Figure 3.2: NPV Sensitivity Analysis



Source: CERI

Not surprising, the choice of the discount rate will either make or break the economics of a refinery. In this case, increasing the discount rate to 17 percent drops the NPV of the refinery

into the negative value, -$1,251 million, whereas decreasing the discount rate to 13 percent will boost the NPV to $2,980 million from the baseline value of $533 million.

After the discount rate, changes to capital costs have the greatest impact on NPV. Oil refining is a capital-intensive business. Planning, designing, permitting and building a new medium-sized refinery is a 5-7 year process with costs ranging from $7-10 billion, not including land acquisition. The cost varies depending on the location (which determines land and construction costs[37]), the type of crude to be processed and the range of outputs (both of the latter affect the configuration and complexity of the refinery), the size of the plant and local environmental regulations. Varying capital costs by 25 percent will change the NPV by almost the same magnitude, but in the opposite direction.

After the refinery is built, it is expensive to operate. Fixed costs include personnel, maintenance, insurance, administration and depreciation. Variable costs include crude feedstock, chemicals and additives, catalysts, maintenance, utilities and purchased energy (such as natural gas and electricity). To be economically viable, the refinery must keep operating costs such as energy, labour and maintenance to a minimum. Like most other commodity processors (such as food, lumber and metals), oil refiners are price takers: in setting their individual prices, they adapt to market prices.[38] In the sensitivity analysis the 25 percent increase in operating costs reduced the NPV by $112 million and vice versa.

Other factors that could make the project uneconomic are the prices of crude oil and diesel, with diesel prices having a larger impact than crude prices. Dropping diesel and oil prices by 20 percent over the project life makes the project's NPV negative and vice versa.[39] For example, reducing diesel prices by 20 percent causes the NPV to be -$701 million. Since refineries have little or no influence over the price of their input or their output, they must rely on operational efficiency for their competitive edge. The project would break even (i.e., NPV=0) when the oil price is US$84.81/bbl (in 2013 dollars), at an assumed discount rate of 15 percent.

The social costs of emissions varied significantly depending on the chosen discount rate for these costs. Generally, the lower the discount rate, the more social cost incurred in the future is placed on society today. In other words, the cost of polluting has more "value" today than what's left for future generations. Hence, choosing a smaller discount rate reduces the NPV of the project.

Table 3.1 summarizes the NPV for all the cases.

[37] For example, building a comparable project on the US Gulf Coast costs less than half of what it does to erect a plant in Alberta according to IHS CERA's "Extracting Economic Value from the Canadian Oil Sands: Upgrading and Refining in Alberta (Or Not)?".

[38] Persistently low profitability may reduce investment in refineries, which could ultimately constrain domestic/ regional capacity and result in higher product prices. Low profitability also puts pressure on refiners to reduce operating and fixed costs because alternative supplies are almost always an option.

[39] The differential between diesel and oil prices is not constant. The differential narrows in the latter part of the time period as oil prices grow faster than diesel prices.

Table 3.1: Sensitivity Cases

Variable	Base Line	Change to the Variable	Resulting NPV	Change from Baseline NPV
CCS Unit	CCS installed	No CCS unit	$1,994.1	$1,461.34
Discount Rate	15%	+2%	-$1,251.1	-$1,783.9
		-2%	$2,979.9	$2,447.1
Oil Prices[40]		+20%	$1,150.3	$617.5
		-20%	-$84.8	-$617.5
Diesel Prices[41]		+20%	$1,761.6	$1,228.8
		-20%	-$700.6	-$1,233.4
Capital Costs	$8.5 billion	+25%	-$1,336.5	-$1,869.2
		-25%	$2,389.2	$1,856.4
Operating Costs	$164 million/year	+25%	$420.5	-$112.2
		-25%	$645.0	$112.2
Disc. Rate for Emissions	3%	0%	$297.3	-$235.4
		1%	$469.7	-$63.1
Debt Financing	40%	+10%	$188.6	-$344.1
		-10%	$876.9	$344.1

Source: CERI

[40] See Chapter 2, Revenues section under Benefits, page 17.
[41] Ibid.

Chapter 4: Conclusions

One view of refining challenges in Canada comes from the IHS CERA report – Extracting Economic Value from the Canadian Oil Sands: Upgrading and Refining in Alberta (Or Not)?

At one time, oil sands developers upgraded their heavy crude into light products before shipping them to market. Today most operators send their heavy crude directly to markets. This new circumstance has spurred a debate about value-added upgrading and refining. The following comments focus on three key issues raised in the IHS CERA report and that have direct relevance to the refining economics discussion:

- Alberta greenfield upgrading economics are challenged by an outlook for a narrow price difference between light and heavy crudes and high construction costs. Both factors discourage investment in upgrading equipment or building new refineries.
- Instead of building new upgraders or refineries, modifying existing refinery capacity to process oil sands is the most economic way to add processing capacity. Modifying an existing refinery is more economic than building a new refinery. However, refinery conversions face challenging market conditions in North America. With ample supplies of light crude, refiners have little motivation to undertake substantial investments to convert refineries to consume heavy crudes.
- For a greenfield refinery focused on oil sands, the strongest investment return is in Asia, where demand is growing. Although the potential is not as strong as in Asia, under the right conditions the economics of new refinery projects in Alberta and/or British Columbia might be possible. Asia's advantage is primarily the result of lower project costs (at least 30 percent less than in North America). Assuming a new refinery project in Alberta or B.C. consumes bitumen, manages to keep capital costs to a minimum, maximizes diesel production, and does not oversupply its market – the economics might be possible.

In this study, CERI conducted a preliminary cost-benefit analysis for a greenfield refinery using up-to-date information to estimate the costs and benefits of the project. The CBA results suggest that a greenfield commercial refinery project is net socially beneficial. However, if the average oil price drops below $85 over the life of the project – a real possibility and a current reality[1] – the project would be a net cost to society. Also other factors that could deem the project to be a net cost (that were not part of the evaluation) include potential GHG damage costs from final consumption emissions, opportunity cost of water consumption, risk of reclamation failure, and interference with other commercial activities.

The CBA exercise was valuable in demonstrating the usefulness of the method as a framework for evaluating project costs and benefits. The CBA presents an alternative assessment of costs and benefits to an environmental impact assessment which assumes that all impacts associated

[1] At the time of writing, the WTI price was just above US$77/bbl.

with the project are incremental and focuses on economic impacts instead of costs and benefits. The CBA also makes clear that there are other costs of the project not included in the EIA. For example, costs to government and land degradation and its restoration are not minor. Finally, there are also environmental social costs. Depending on the chosen discount rate, environmental costs of GHGs could be in a range of $359 to $3,855 million when the project is fully operational. Criteria air contaminants further contribute over $90 million in overall pollution costs. The CBA demonstrates that the environmental impacts of the project are far from insignificant. In sum, the CBA provides a different perspective on the project's value to society than the EIA. In doing so it raises the awareness around the pros and cons of the project by not relying upon measures of gross impacts.

A limitation of the CBA is that it relies upon individuals' valuations of gains or losses, a practice which runs into conflict with judgements that society makes collectively. A second limitation is with respect to impacts that occur in the future. As the CBA considers the time-value of money, future benefits such as diesel sales in the latter years of the project and future costs such as reclamation are diminished to the point of inconsequence by discounting. From a financial perspective this is perfectly correct because money spent today is considered more valuable than money spent in the future, but from the perspective that environmental impacts could substantially reduce the quality of life for future generations this practice may underestimate the magnitude of those costs. Furthermore, many impacts are not quantifiable. The lack of a framework that allows quantification for costs such as loss of recreational land, or higher health care costs from pollution, is a major limitation of the method. Despite these limitations, the study shows that the CBA provides a useful framework for assessing the net impacts of projects and identifying issues of societal importance and could serve as an alternative tool to EIA. This assessment is especially relevant today given increasing scrutiny on the legacy and cumulative effects of major projects' development.

Drawing firm conclusions about the social value of the value-added potential of an oil refinery is difficult given the data limitations. This study is also limited in that CERI did not examine the distribution of benefits and costs of the project, social impacts such as community disruption (if any), effects of development on the Canadian economy (such as price and secondary market effects), potential benefits to Canada from elevated domestic energy production, or benefits of reduced GHG emissions globally due to carbon capture unit in the refinery design. A more comprehensive study of a single project, as well as a study of the net social benefit of value-added industry as a whole, would also have to consider other options to development such as different designs, stronger environmental standards, and different timings and provinces for project construction to reduce bottlenecks caused by rapid expansion of the energy sector. In other words, there are many factors that influence whether a project is socially beneficial, and the results of this study should not be taken as absolute truths, but rather as a discussion that the impacts and benefits of projects extend beyond immediate economic viability.