

THE NORTH WEST REDWATER STURGEON REFINERY: WHAT ARE THE NUMBERS FOR ALBERTA'S INVESTMENT?

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SUMMARY

Since 2006, the government of Alberta has tried to increase the volume of raw bitumen upgraded and refined in the province. More specifically, the Alberta Petroleum Marketing Commission (APMC) and Canadian Natural Resources Ltd. (CNRL) have entered into agreements with a facility northeast of Edmonton called the North West Redwater (NWR) Sturgeon Refinery. The NWR Sturgeon Refinery is designed to process 79,000 barrels per day (bpd) of feedstock, consisting of 50,000 bpd of bitumen and 29,000 bpd of diluent (referred to as dilbit). The refinery will produce petroleum products consisting of approximately 40,000 bpd of low sulphur diesel, 28,000 bpd of diluent and 13,000 bpd of other lighter petroleum products. It will also be able to capture 1.2 million tonnes per year of carbon dioxide emitted from the refinery's operations. This captured carbon dioxide will be compressed, put into a pipeline and then injected into an existing oil field in order to achieve increased production of crude oil (referred to as enhanced oil recovery or EOR). It is the first refinery built in Canada since 1984, and the first one in Canada to refine bitumen into petroleum products such as diesel fuel. It differs from the upgrader built in Lloydminster which only upgrades bitumen into synthetic crude oil that requires further refining at a conventional refinery in order to produce petroleum products.

This paper gives a description of the structure of this support by APMC and CNRL using a mechanism whereby those two parties agree to enter into tolling agreements to process the diluted bitumen feedstock into refined petroleum products for sale. Under the tolling agreement, APMC and CNRL retain ownership of the diluted bitumen as it is refined into petroleum products. APMC and CNRL then sell such petroleum products,

and pay a tolling fee to the NWR Sturgeon Refinery for the refining service provided. The paper also uses an economic model in Excel to give a projection of the economics of this facility for the first full year of operation. The objective is to put numbers to a project that has been the subject of much qualitative discussion.

The Excel economic model contains base case assumptions for a number of variables such as the capital cost of the refinery, the financing costs associated with such capital costs, the operating costs of the refinery, the cost of the diluted bitumen feedstock and the price of the petroleum products produced by and sold from the refinery.

Based on these base case assumptions, the Excel economic model shows that in the first full year of operation of the NWR Sturgeon Refinery in 2019, the two toll-paying entities, APMC and CNRL, are projected to lose a cash amount of about \$24 million (about \$1 per barrel of diluted bitumen supplied). This loss is based on a comparison to the toll payers' alternative of just selling the diluted bitumen feedstock at market prices.

The paper then uses the economic model to do a sensitivity analysis to show the effect of a lower or higher price of diluted bitumen feedstock, as well as the effect of a lower or higher price of the produced petroleum products. If the cost of the diluted bitumen feedstock were lower, or the price of the petroleum products were higher, then APMC and CNRL would earn a profit. If the converse occurred (feedstock costs higher or petroleum product price lower), then the loss to APMC and CNRL would be greater than \$24 million.

Finally, the paper attempts to create a template for governments to use when they consider whether or not to provide financial assistance to various projects.

I. INTRODUCTION

In the last 50 years in Alberta, the production of oil and gas from conventional sources has declined, and the production of bitumen from the oilsands in northeastern Alberta has increased (Alberta Energy, 2018). Current production of bitumen from the oilsands in 2016 was 2.5 million barrels per day, a number that may increase to as much as 3.7 million barrels per day by 2030 (CAPP, 2017).

The government of Alberta has taken a keen interest in the oil and gas industry ever since the first discovery was made over a century ago. Given the rise in bitumen production, it has focused its more recent policies on the development and production of bitumen. More specifically, it has focused on the upgrading of such bitumen into more value-added products. This paper describes one such policy initiative, namely the Alberta government's involvement with a publicly owned company named Canadian Natural Resources Ltd. (CNRL) and a private company named North West Refining who are 50/50 partners in the North West Redwater Partnership which owns the refinery. The three entities are involved in the construction and anticipated operation of a facility named the North West Redwater (NWR) Sturgeon Refinery.

Before looking at the specifics of the Alberta government policy and the NWR Sturgeon Refinery, it is helpful to look at the historical background for bitumen production in Alberta.

II. THE HISTORY OF BITUMEN PRODUCTION IN ALBERTA

(a) The Characteristics of Bitumen

The existence of the oilsands in Alberta has been known for centuries, and predates the discovery of conventional oil and gas in Alberta. Early explorers in northeast Alberta could literally smell the raw bitumen at the surface, and observed that the Indigenous people used the bitumen to seal their canoes.

Notwithstanding this early awareness of the oilsands, the commercial development of bitumen has been a long and involved process. A good summary of the history is contained in an article in the *Edmonton Journal* (2013).

The main reason for this difficulty in development is that bitumen is fundamentally different from most conventional oil. It is referred to as heavy – not only because it weighs a lot, but also because it is extremely viscous. It resembles peanut butter, versus the corn oil-like viscosity of most conventional oil (BP, 2011).

The extreme viscosity is due to the fact that many of the hydrogen atoms in the bitumen have evaporated, leaving behind a crude oil with a higher carbon-to-hydrogen ratio.

(b) Initial Production of Bitumen in the 1970s and 1980s

The consequence of this greater viscosity is that it is more difficult and more expensive to transport and refine bitumen into petroleum products than to transport and refine conventional crude oil into petroleum products. The first commercial production of bitumen commenced in the late 1960s by Great Canadian Oil Sands (GCOS), whose operations were eventually taken over by the present-day Suncor Energy Inc. (2018a).

Raw bitumen had no value at that time since it could not be used as a feedstock in most refineries. As a result, the GCOS facility included an industrial process known as upgrading, in which the raw bitumen was upgraded into synthetic crude oil that could be used as feedstock for most refineries.

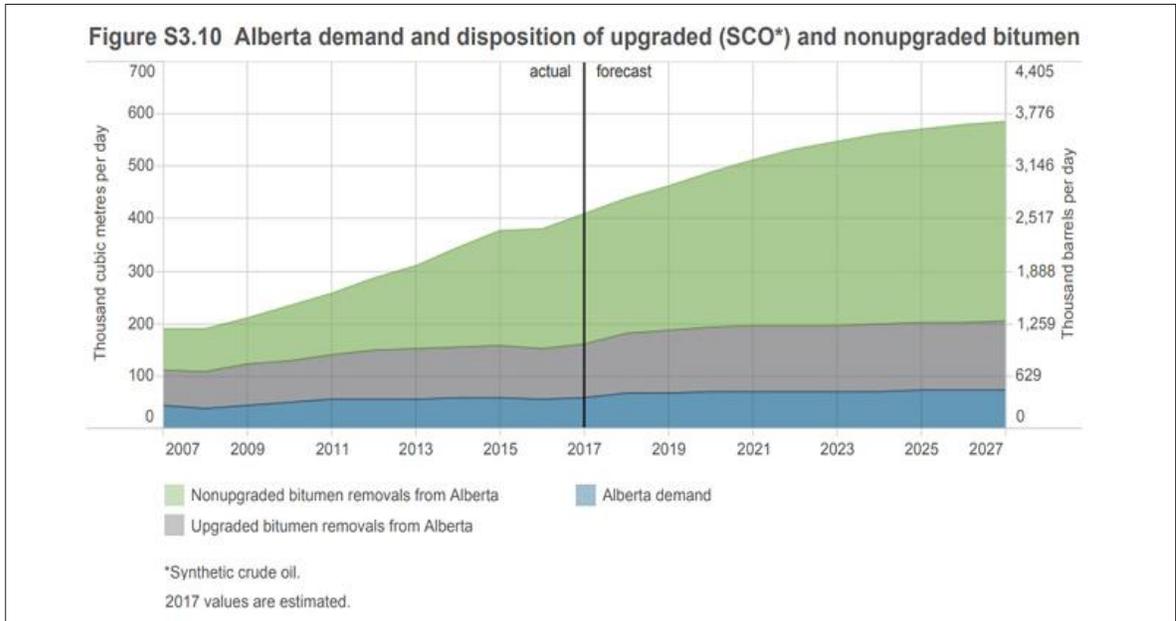
Several other bitumen operations commenced in the next 30 years: Syncrude, Shell Albion, CNRL Horizon and Nexen Long Lake. Each bitumen-producing operation included an upgrader to produce synthetic oil. In addition, a stand-alone upgrader that upgrades bitumen into synthetic crude oil was built in Lloydminster and is currently operated by Husky Energy.

Starting in the 1980s, some refineries in the Gulf Coast and Midwest areas of the United States added specialized equipment known as cokers (to reduce the carbon content) or hydrotreaters (to increase the hydrogen content). This specialized equipment permitted the refining of diluted bitumen directly into petroleum products. The incentive to make this capital investment in specialized equipment was that the cost of bitumen feedstock was significantly less than conventional crude (referred to as the heavy oil discount).

In essence, these investments in various U.S. refineries collectively created several virtual upgraders that could convert previously worthless bitumen into more valuable petroleum products.

Alberta producers of bitumen were now able to sell diluted bitumen into a newly created bitumen market in the United States. The bitumen had to be mixed with light hydrocarbons called diluent in order to reduce the viscosity and thereby permit the diluted bitumen to flow in a pipeline and be shipped to these U.S. refineries. This explains why Imperial's Kearl and Cold Lake operations plus Suncor's Fort Hills mine do not have upgraders, and therefore sell diluted bitumen into the United States and other markets.

The following chart summarizes the production and use of bitumen in Alberta.



Source: Alberta Energy Regulator

(c) Canadian Refined Product Markets

The refined products infrastructure in Western Canada was built on an east-west axis. Most of the supply of petroleum products in the four western provinces comes from three large refineries in or near Edmonton. The current demand/supply balance is such that the supply from these three refineries is less than total Western Canada demand. The balance of supply comes from the Parkland (formerly Chevron) refinery in Burnaby plus imports, primarily from the United States. This situation is known as import parity, in that the marginal barrel of supply comes from imports into the Vancouver area. Very little infrastructure exists that can export petroleum products out of Alberta into the northern United States, other than rail and trucking.

Historically, the feedstock for these three refineries has come from conventional and synthetic light crude oil. This conventional and synthetic feedstock supply has been stable for decades and continues to be stable today. As a result, there was very little incentive to invest in the equipment necessary to refine diluted bitumen into petroleum products. The higher cost of construction of this type of equipment in the Alberta market was another deterrent to making such investments. The equipment at the three refineries is relatively simple from a chemical engineering perspective, and does not include the cokers and hydrotreaters necessary to process diluted bitumen as feedstock. As a result, there is very little refining capacity in Canadian refineries that will permit the processing of diluted bitumen as a feedstock.

Some of the diluted bitumen that is processed in Canada is for asphalt production at the Imperial refinery at Strathcona and the Husky Energy asphalt plant in Lloydminster with a processing capacity of 29,000 bpd (Husky Energy, 2017a).

Most of the diluted bitumen used in in the Shell Albion upgrader is upgraded to synthetic crude and then used as feedstock for the Shell Scotford refinery, Suncor's Edmonton refinery has a coking facility and can process 29,000 bpd of bitumen, which is about 20 per cent of that refinery's capacity (Suncor, 2017). In addition, Imperial Oil's Sarnia refinery has a coking facility that has enabled it to process raw bitumen (Wikipedia, 2018a).

The Husky upgrader at Lloydminster commissioned in 1994 is the only stand-alone upgrader in Canada, with an ability to process 82,000 bpd of heavy oil.

(d) The Canadian Market for Diluted Bitumen

The lack of investment in Canadian upgrader capacity or refineries that could use diluted bitumen as a feedstock, combined with the increase in bitumen since the 1990s, meant that there was an excess of diluted bitumen supply in Alberta.

The consequence was that this excess supply was earmarked for export, primarily to the United States. As a result, and in contrast to the refined products market, the crude oil transportation infrastructure for the shipment of diluted bitumen has grown primarily on a north-south axis since the 1990s.

The destinations for these diluted bitumen exports are refineries in the United States. Most of these U.S. refineries have been in existence for a long time, and are located in either the Gulf Coast (Texas or Louisiana) or in the Midwest (Illinois, Wisconsin, Minnesota, Ohio or Colorado). Not by coincidence, these locations are close to areas of large population (Texas alone has a population two times as large as all of Western Canada). This large population creates a high demand for petroleum products (much higher than Western Canada demand). As a result, many of these refineries have a very large capacity. ExxonMobil's Baytown refinery, for example, has a capacity of 561,000 bpd, or three times the 185,000 bpd capacity of Imperial's Strathcona refinery (ExxonMobil, 2017).

These refineries are also close to various sources of feedstock supply. Gulf Coast refineries in particular have flexibility of supply since they have access to ocean tankers as well as pipelines. For several decades, much of the supply to these Gulf Coast refineries has been heavy crudes from Mexico (called Maya) or Venezuela. In order to process this heavy oil feedstock, these refineries invested in more complex cokers and hydrotreaters to use the cheaper heavy oil as feedstock. More recently, production of Maya crude has declined due to the natural decline of the Mexican oil fields, and production from Venezuela has declined due to domestic turmoil. As a result, U.S. refiners have looked to Canadian diluted bitumen as a substitute supply. Canadian diluted bitumen has created a new benchmark called Western Canadian Select (WCS), with an accompanying quoted price in oil markets.

The fact that many of these refineries were very large meant that these investments were made on an incremental brownfield basis versus a brand new greenfield basis. Combined with the fact that productivity in the Gulf Coast was higher than in the Alberta market, this meant that the cost of increasing the capacity to use heavy oil as a feedstock was significantly less for Gulf Coast refineries than it would have been for Canadian refineries. This lower cost is often expressed as cheaper by so many cents on the dollar for the equivalent investment in capacity.

The bottom line result is that while the U.S. refiners invested in more complex refinery configurations with higher processing capability that use cheaper feedstocks like WCS and Maya, Canada did not (Wikipedia, 2018b).

(e) Strategies of Canadian Heavy Oil Producers

Many Canadian companies have employed other strategies to deal with their bitumen production. Given the above discussion on relative cost of investment in diluted bitumen feedstock, it is not surprising that these strategies involve using refineries in the United States that have been adapted to use diluted bitumen as a feedstock.

Cenovus Energy Inc. (2017) produced about 150,000 bpd of bitumen in 2016. Cenovus also has a 50 per cent interest in two refineries in the United States (one in Illinois, the other in Texas) operated by ConocoPhillips (now Phillips 66). These two refineries have a total refining capacity of 460,000 bpd and a heavy crude processing capacity of 255,000 bpd. Cenovus processes a portion of its bitumen production into refined petroleum products in these two refineries.

Husky Energy (2017b) produced 170,000 bpd of bitumen and heavy oil in 2016, an amount that is expected to increase in the future. It has also acquired refining capacity in existing refineries in the United States. It owns a refinery in Ohio in which it is currently making investments to increase the refinery's ability to process an additional 40,000 bpd of heavy Canadian crude. It also owns 50 per cent of a refinery in Ohio in which recent investments will increase the refinery's ability to process an additional 65,000 bpd of heavy Canadian crude, some of which will come from Husky's Canadian heavy oil operations.

More recently, in August 2017 Husky purchased a refinery in Superior, Wisconsin with a capacity of 50,000 bpd that can convert heavy oil into petroleum products (Healing, 2017).

Finally, Suncor has invested in refining capacity of 98,000 bpd in Colorado that can process diluted bitumen as feedstock.

The key message of these strategies is that Cenovus, Husky and Suncor have chosen to capture the benefits of upgrading a significant portion of the bitumen they produce by using existing large-scale refineries in the United States with the accompanying economies of scale and the benefits of lower incremental investment in cokers and hydrotreaters. Other bitumen producers have chosen to export their bitumen to other refiners in the United States that have invested in their existing refineries so as to be able to refine bitumen.

The United States has recently increased its production of light oil from the Permian Basin in Texas by several million barrels per day. Since many of the Texas-based refineries are equipped to process diluted bitumen, this increase in production of light oil will mean that the United States will continue to be a major importer of heavier crudes that suit the configuration of its refineries, but a larger exporter of light crude and refined products (IEA, 2017).

III. THE ALBERTA GOVERNMENT'S REACTION TO BITUMEN EXPORT

The government of Alberta noticed the decline in the percentage of bitumen processed in Alberta. When he was running for the leadership of the Conservative party in 2006, Ed Stelmach said: “Shipping raw bitumen is like scraping off the topsoil, selling it, and then passing the farm on to the next generation” (Steward, 2011).

As a result, the Alberta government embarked on a policy to encourage the upgrading of bitumen in Alberta. More specifically, it asked bitumen producers to pay the royalty on such production in actual barrels of bitumen, a process referred to as bitumen royalty-in-kind (BRIK). The theory was that Alberta could then use this BRIK bitumen to guarantee a long-term supply of bitumen that would encourage investors to build stand-alone upgraders/refineries in Alberta. There was an initial optimism that several upgraders would be built as a result of BRIK.

The recession of 2008 changed the optimism for the construction of upgraders or heavy oil refineries. The Alberta government concluded that additional support was required to encourage investment. Eager to keep one of former premier Stelmach's signature commitments, the government proceeded to sweeten the deal to keep the one remaining project afloat — the North West Upgrader in Sturgeon County.¹

IV. THE ECONOMICS OF REFINING BITUMEN

(a) The Basic Economic Decision

The decision whether or not to refine bitumen into petroleum products is a choice between two alternatives. The first choice would be just to mix the bitumen with lighter hydrocarbons such as naphtha (referred to as diluent) and load it into a pipeline at a terminal such as the one at Hardisty, Alberta. There is currently a diluted bitumen market in Canada that uses a posted benchmark price known as Western Canadian Select (WCS) at Hardisty to determine the price of diluted bitumen (*Oil Sands*, 2018a).

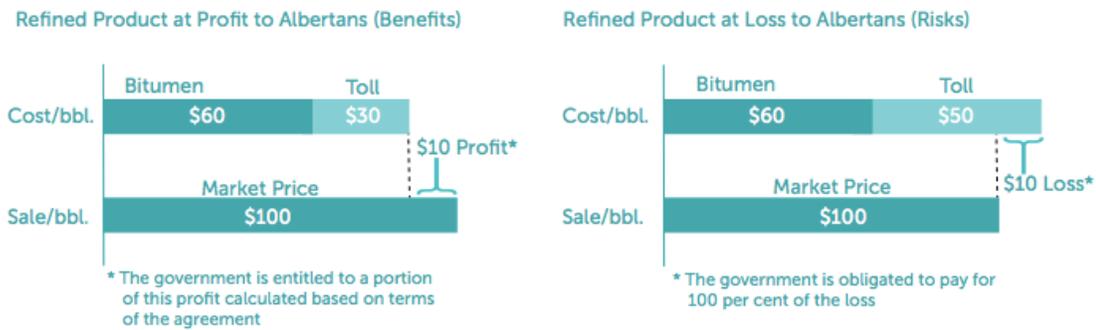
¹ See Morton (2015) on the policy and political process over several years that lead to the agreements supporting the NWR Sturgeon Refinery. Morton, who was Minister of Finance for Alberta when the NWR Sturgeon Refinery deal was negotiated, describes how the Alberta government came to assume the risks for both revenues from upgrading and capital and operating costs.

The second choice is to refine the diluted bitumen into petroleum products.

An Excerpt from the Auditor General's Report on the Choice to Refine Diluted Bitumen into Petroleum Products

The refined product will typically have a higher market value than the bitumen the government supplies to the refinery—but the difference between the market price and the bitumen cost has to be greater than the toll for the government to make a profit. One risk in this scenario comes from the fact that the market price of refined oil is unpredictable, so a profit after the toll is paid is uncertain. A second risk is that increases in the construction costs of the refinery lead to increases in the toll as [the NWR Sturgeon Refinery] seeks to recover costs. A larger toll makes it harder for the government to make a profit.

Profit/Loss After Toll Payment



Source: Report of Alberta Auditor General. Chapter on the Sturgeon Refinery, February 2018

The rest of this paper seeks to quantify the numbers in the above diagram.

(b) Factors Affecting the Economics of Refining Diluted Bitumen

As with any investment, several risks must be taken in a decision to upgrade or refine bitumen. The most important of these risks are:

1. the anticipated revenue stream from the sale of petroleum products;
2. the feedstock costs of the diluted bitumen;
3. the capital costs of building the refinery;
4. the operating costs of operating the refinery;
5. the cost of financing such capital costs; and
6. the reliability of the operation, referred to as the utilization factor.

The construction of an economic model for the NWR Sturgeon Refinery requires the making of assumptions for each of these items.

(c) Anticipated Revenue Stream

(i) Volumes of Petroleum Products Produced

The first step in determining a revenue stream is to make an assumption about the volumes of petroleum products to be produced. An upgrader uses bitumen as a feedstock and upgrades it to synthetic crude that is similar in composition and value to conventional crude. A refinery uses conventional crude as feedstock and refines it into petroleum products such as diesel fuel. The NWR Sturgeon Refinery is a heavy oil refinery designed to perform both these functions by converting bitumen into petroleum products such as low sulphur diesel fuel, distillate and other light petroleum products, mostly diesel fuel.

The NWR Sturgeon Refinery is designed to use the following feedstock and produce the following petroleum products.

Feedstock	Petroleum Products
50,000 bpd bitumen	40,250 bpd low sulphur diesel
29,000 bpd diluent	8,790 bpd low sulphur VGO
	3,363 bpd of propane/butane
	28,266 bpd of diluent
	4,500 tons of CO ₂ per day

Note that the diluent in is almost balanced by the diluent out. Therefore, the main economic activity is the transformation of 50,000 bpd bitumen into 52,403 bpd of petroleum products. The increase in volume is due to the addition of hydrogen as part of the refining process (North West Refining, 2018a).

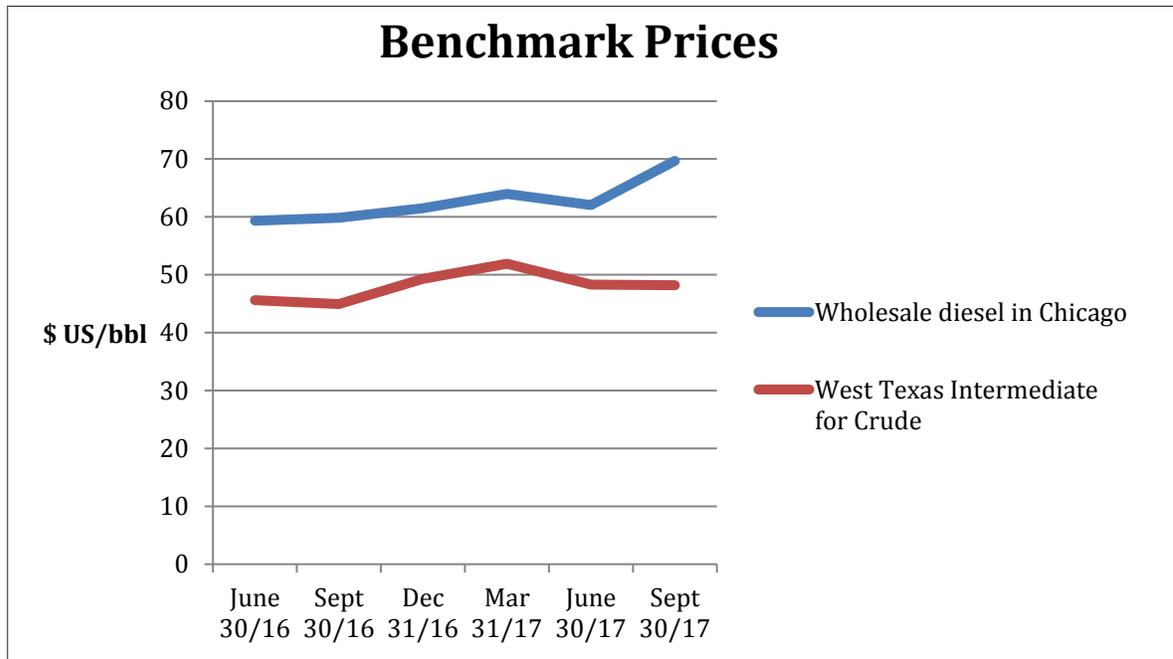
(ii) Prices for Petroleum Products

The second assumption to be made is the sale prices for the various petroleum products. The pricing of petroleum products is usually described as a percentage above a benchmark crude price. This percentage is usually referred to as the crack spread, since it is the difference in price caused by the refining process that “cracks” (the jargon of chemical engineers) the feedstock molecules into petroleum products. For North America petroleum products, that benchmark is the price of West Texas Intermediate, or WTI. The base case assumptions are as follows, with prices shown as a percentage of WTI:

Petroleum Product	Percentage of WTI
Low Sulphur Diesel	140 per cent
Low Sulphur VGO	105 per cent
Propane/Butane	85 per cent
Diluent	105 per cent
CO ₂ net sale proceeds	\$15/tonne

The assumption for the diesel crack spread is a critical one for the NWR Sturgeon Refinery. The higher the crack spread, the more the revenue.

In order to test the validity of this assumption, it is useful to look at actual industry experience. For example, there is a benchmark for wholesale diesel fuel known as the Chicago ultra-low sulphur diesel to determine the price of diesel fuel. The price for diesel received by a refinery is the wholesale price, not the retail price paid by the final consumer. The graph below illustrates the historical prices for these two benchmarks in the most recent six quarters, based on data obtained from Husky Energy.



Source: Q3 2017 Husky Energy MD&A, 3

The data in this graph indicate an average crack spread for diesel of about 130 per cent in the past six quarters. The crack spread in the third quarter of 2017 widened to 145 per cent, likely due to the closing of refineries in Houston as a result of Hurricane Harvey.

A second data point is to use the petroleum product prices published by the Kent Group (2018). The prices from that source are closer to home, and give wholesale diesel prices (referred to as rack prices) for Calgary and Edmonton. The data show a higher crack spread for the sale of wholesale diesel out of Calgary and Edmonton in the range of 150 per cent or more.

This higher crack spread assumes that the seller of diesel will realize the full rack price. It is entirely possible that a new entrant into the diesel market such as the NWR Sturgeon Refinery may have to range further away from these two cities in order to market its diesel production. The new NWR Sturgeon Refinery production may have a sufficient effect on the existing diesel wholesale market in Western Canada so that it changes from import parity to export parity. In other words, the marginal barrel in this Western Canada market may be destined for export. Given that NWR Sturgeon Refinery is a new entrant and does not have existing domestic customers, it may have to export a significant portion of its

diesel production, which would be at a lower price than the Calgary and Edmonton market for two reasons.

First, it costs money to transport the diesel to more distant customers, whether by rail or by truck. These transportation costs will reduce the netback proceeds that a refiner realizes. Second, the upper northern states of Montana, Wyoming, Idaho and North and South Dakota already have diesel supply from existing refineries in Billings, Montana and Colorado. Exports of diesel into the United States will have to compete with this existing U.S. supply, and will therefore likely result in a reduced price.

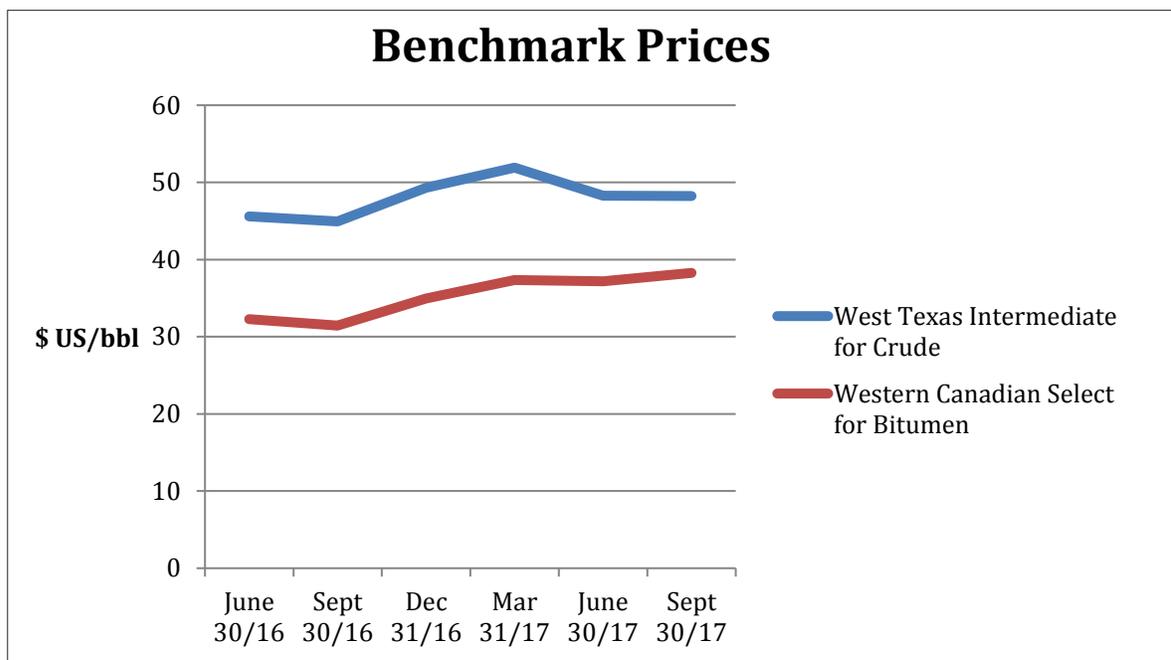
As a third data point, the Dominion Bond Rating Service (DBRS) used an assumption of a crack spread for diesel of 130 per cent over WTI when it performed its economic analysis to rate the senior bonds issued by the NWR Sturgeon Refinery (DBRS, 2017a).

Given all this uncertainty, it makes sense to use a base case crack spread of 140 per cent, with a sensitivity case using 130 per cent and 150 per cent.

Finally, an assumption of \$15 per tonne is a reasonable one to use for the sale price of CO₂ (Skinner, 2015).

(d) Feedstock Costs

As mentioned above, there is currently a diluted bitumen market in Canada that uses a benchmark price known as Western Canadian Select (WCS) to determine the price of diluted bitumen. The WCS price has historically moved in conjunction with WTI. The graph below illustrates the historical prices for these two benchmarks in the most recent six quarters, based on data obtained from Husky Energy.

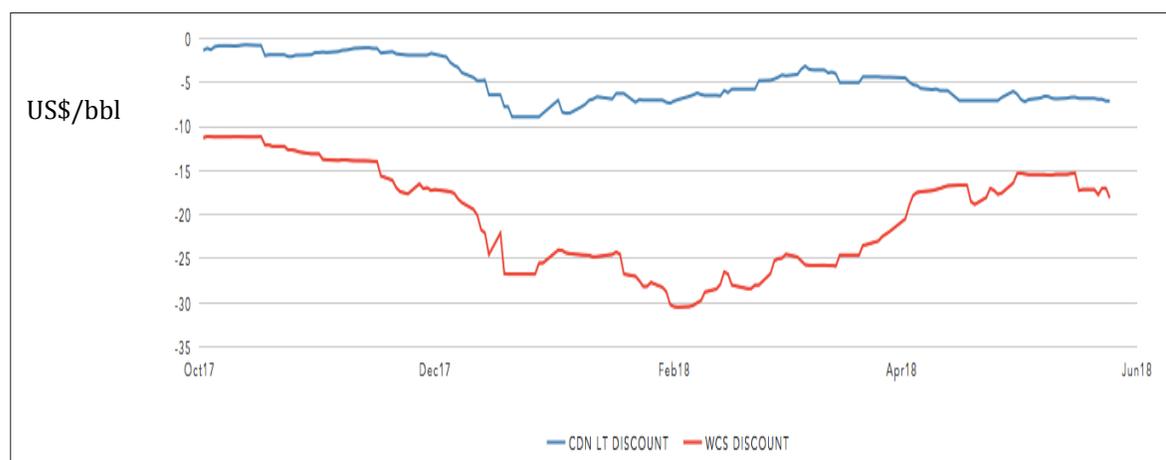


Source: Q3 2017 Husky Energy MD&A, 3

The data in this graph indicate that in the past six quarters, the average heavy oil discount has been about US\$12/barrel, with a high of US\$15/barrel and a low of US\$10/barrel.

Again, it makes sense to use additional market data to determine a base case number for the heavy oil discount. The data from a service called *Oil Sands Magazine* shows real-time prices for WTI and WCS, both at Hardisty in Alberta and Cushing in Oklahoma. The difference between the two locations for WCS is presumably due to the cost of transporting the diluted bitumen from the gathering point at Hardisty to the central location in Cushing. These transportation costs are in the order of US\$8/bbl to US\$12/bbl if transported by pipeline, and US\$16/bbl to US\$18/bbl if transported by rail (Paul and Farhatha, 2018).

The last year shows a wide variation in the heavy oil discount from US\$10/barrel to US\$30/barrel, as shown below. The heavy oil discount was widest in the first quarter of 2018 (likely due to the outage of the Keystone pipeline), but has recently narrowed to a range of US\$15 to US\$18 per barrel in May of 2018 (*Oil Sands*, 2018b).



Source: Oil Sands Magazine

As a third data point, the DBRS used an assumption of a heavy oil discount of US\$15/barrel when it performed its economic analysis to rate the senior bonds issued by the NWR Sturgeon Refinery (DBRS, 2017b).

The heavy oil discount has been a topic of much public discussion in recent times. The economic rationale for the expansion of the Kinder Morgan pipeline has been to increase market access to new tidewater customers so that export of diluted bitumen will not just depend on U.S. customers. The belief is that this increased access to tidewater will decrease the heavy oil discount from its current high amount.

Given all this uncertainty, it makes sense to use a base case heavy oil discount of US\$18/barrel, with sensitivity cases using US\$21/barrel and US\$15/barrel.

(e) The Capital Costs of a Refinery

The capital cost of a refinery will often use a metric of unit costs referred to as dollars per flowing barrel. This metric takes the capital cost and divides by the refining capacity in barrels per day.

As with many investments, it is useful to start with a comparable investment already done. Real estate agents use this comparable concept when they appraise the value of a house.

As mentioned above, a recent comparable is when Husky purchased an existing refinery in Superior, Wisconsin in November of 2017. Husky has stated it will make a further investment in the first half of 2018 to increase the heavy oil processing capacity of the refinery. The purchase price was US\$527 million (approximately Cdn\$670 million) for a refinery that can refine 50,000 bpd of heavy oil into refinery products. Doing the math, this gives a metric of about Cdn\$13,000 per flowing barrel. A project to increase the heavy oil processing capacity at the Superior refinery is expected to be completed in the first half of 2018 (Husky Energy, 2017c).

(f) The Operating Costs of a Refinery

Again, it is useful to look at an existing facility in order to obtain a comparable metric for operating costs. A comparable would be the operating costs of the Husky Lloydminster upgrader. Husky used a figure of about \$10/bbl in a presentation for the first half of 2017 (Husky Energy, 2018a).

(g) Financing Costs

An investor financing a refinery would normally use a mixture of debt and equity to fund the capital cost. Given the risks and uncertainties of revenue, capital costs and operating costs, it would be reasonable to expect debt to fund 25 per cent and equity 75 per cent, as used by other public refining companies such as Suncor.

As will be seen below, the financing of the NWR Sturgeon Refinery is not a normal financing structure.

(h) Reliability

The nameplate capacity of any refinery is reduced by a factor known as the utilization factor. For example, a refinery with a nameplate capacity of 50,000 bpd and a utilization factor of 90 per cent will only actually produce an average of 45,000 bpd. Utilization factors vary for various facilities due to mechanical turn-around frequency and duration and other downtime caused by poor reliability. Many conventional refineries have a utilization factor of over 90 per cent, whereas bitumen upgraders operated by Syncrude have an historical utilization factor ranging from 71 per cent to 88 per cent (Suncor, 2018b).

Based on market observations over the past 10 years from comparable refineries, DBRS assumed a 90 per cent utilization rate under the base case and stress-tested this factor to 85 per cent (DBRS, 2017c).

In conclusion, a reasonable assumption is 90 per cent, with some sensitivity to see the effect if the utilization factor is less than 90 per cent.

V. THE DEAL WITH THE GOVERNMENT OF ALBERTA AND THE NWR STURGEON REFINERY

(a) Sources of Information

The main sources of financial information for the NWR Sturgeon Refinery are a May 2017 ratings report from the DBRS (2017d) and the financial statements of Canadian Natural Resources Ltd. (CNRL) for the period from 2015 to 2017.

The DBRS report offers many details of the deal between the NWR Sturgeon Refinery, the government of Alberta and CNRL. The NWR Sturgeon Refinery has a website that will periodically update the construction status of the project, but the website does not offer any financial data. The last update on the NWR Sturgeon Refinery website was in May of 2018.

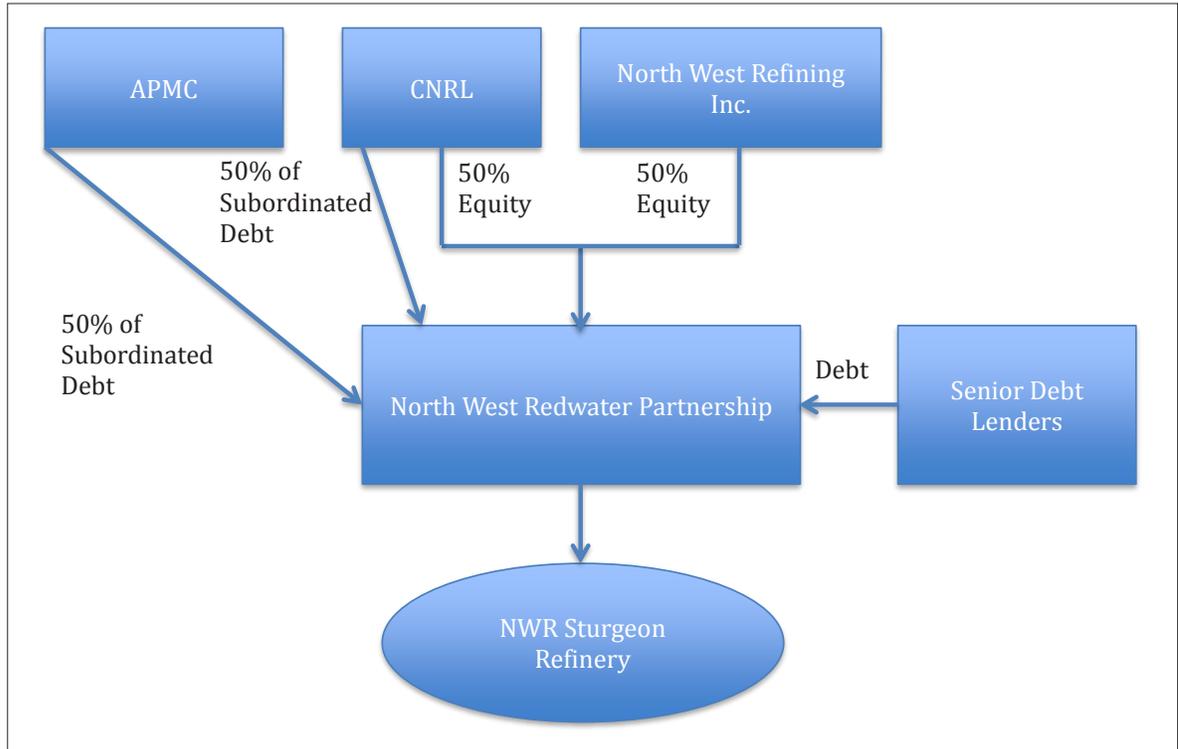
CNRL has stated that the completion of the NWR Sturgeon Refinery will create demand for 79,000 barrels per day of diluted bitumen that will not require export pipelines, which will help reduce pricing volatility in all western Canadian heavy crude oil (CNRL, 2018a).

(b) Legal Structure of the NWR Sturgeon Refinery

The simplified diagrams below illustrate the various legal relationships in the NWR Sturgeon Refinery, namely:

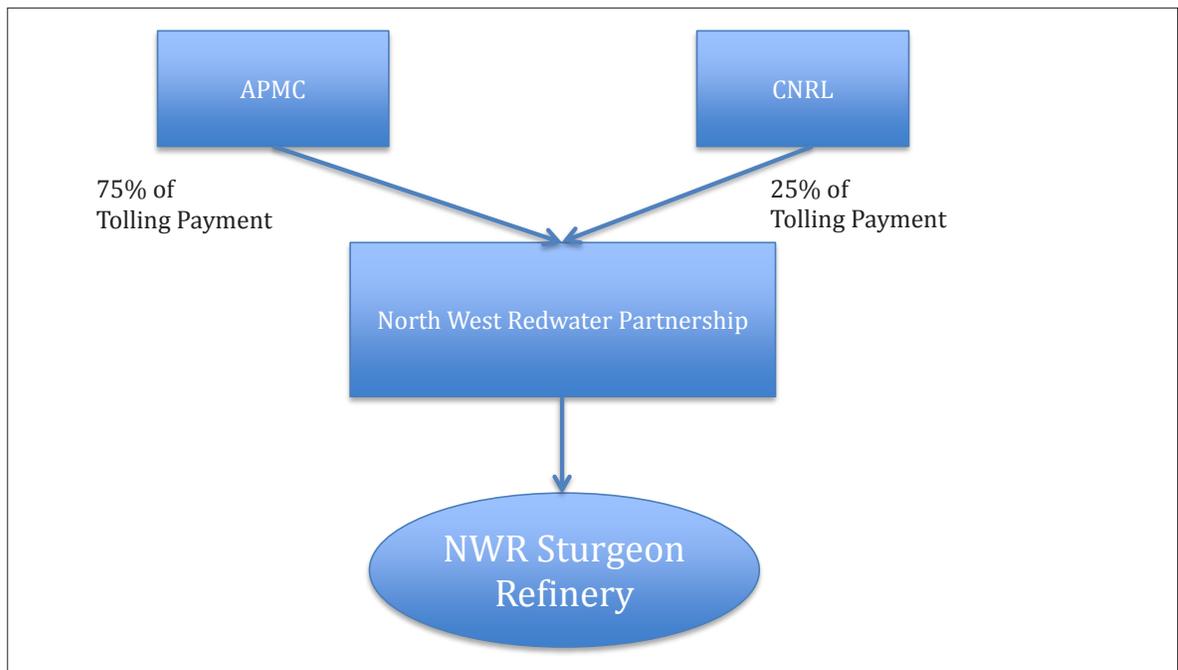
1. the NWR Sturgeon Refinery is owned by the North West Redwater Partnership, which in turn is indirectly owned 50 per cent by Canadian Natural Resources Ltd. (CNRL), and 50 per cent by North West Refining Inc., a private company that was the original proponent of the facility. These owners provided the equity financing for the NWR Sturgeon Refinery, which was about five per cent of the project's financing;
2. as described in more detail further on in the paper, the debt financing has two components; namely
 - a) senior debt financing from bondholders and banks, representing 85 per cent of the project's financing; and
 - b) subordinated debt financing advanced 50 per cent by the Alberta Petroleum Marketing Commission (APMC) and 50 per cent by CNRL, representing about 10 per cent of the project's financing.

Ownership and Debt Financing



3. The tolling agreement in which APMC (75 per cent) and CNRL (25 per cent) agree to supply diluted bitumen feedstock and pay the costs of processing by the NWR Sturgeon Refinery.

Tolling Agreements



(c) Technical Structure of the NWR Sturgeon Refinery

The proponents of the NWR Sturgeon Refinery have envisioned more than an upgrader. Their vision is to have a full refinery that can take diluted bitumen as its only feedstock and process it directly into finished petroleum products that can be sold.

In simplest terms, the NWR Sturgeon Refinery consists of two processing units. The first unit processes the raw diluted bitumen into a feedstock that the second unit can refine into petroleum products.

The second unit is the simpler part of the refinery. It can operate if conventional crude or synthetic crude were the only feedstock. The unit was tested in November 2017 using synthetic crude as a feedstock and produced some amount of diesel fuel that the NWR Sturgeon Refinery donated to various local community service vehicles. This production using synthetic crude is part of the commissioning and start-up process, in that it allows for testing and adjustments in the units that are functioning as at March 2018 (North West Refining, 2017a).

The NWR Sturgeon Refinery made its first diesel from synthetic oil in November of 2017 and has produced about 2.2 million barrels of diesel fuel since December of 2017, or about 15,000 barrels of diesel a day (North West Refining, 2018b).

All of the processing facilities in the first unit of the NWR Sturgeon Refinery were completed in May of 2018. These various processing facilities will go through a commissioning and start-up procedure in the coming months. As of May 2018, 1,400 workers were on site (North West Refining, 2018c).

CNRL (2018b) has indicated that project completion of the NWR Sturgeon Refinery that will enable it to process diluted bitumen is targeted for the fourth quarter of 2018.

(d) Capital Cost

The capital cost of the NWR Sturgeon Refinery was originally estimated to be \$4.0 billion in 2008, and first operation planned to be in 2016 (Morton, 2015).

Costs have risen since that date to \$8.5 billion in 2013, \$9.4 billion in 2017 and most recently, \$9.7 billion in April of 2018, with commercial operation estimated to be in the fourth quarter of 2018 (CNRL, 2018c; Graney, 2018).

It is interesting to contrast this \$9.7 billion capital cost for the NWR Sturgeon Refinery with the previously mentioned \$670 million purchase of a similar 50,000 barrel per day refinery in Wisconsin by Husky Energy. The unit cost for the NWR Sturgeon Refinery using the 79,000 barrels per day of diluted bitumen is projected to be \$123,000 per flowing barrel, versus the \$13,000 per flowing barrel for the Wisconsin refinery.

(e) Financing

(i) General Structure

NWR Sturgeon Refinery has funded the project, including all the financing costs and working capital requirements, through a mixture of equity capital, subordinated debt and senior secured bonds with staggered maturities, supported by a \$3.5 billion revolving senior secured syndicated credit facility (DBRS, 2017e).

The original plan for financing the capital cost of \$4 billion was to use the equity from the original owners (North West Refining Inc. and CNRL) for 20 per cent and the senior debt holders for 80 per cent. When the capital cost increased to \$9.7 billion, the senior debt holders continued to require 20 per cent of the financing to be other than senior debt. It would appear that the original equity investors (particularly North West Refining Inc.) have declined to advance additional financing (DBRS, 2017f). In 2013, APMC and CNRL agreed to make up this financing shortfall by each advancing debt in the form of subordinated debt in the amount of \$350 million each, plus additional debt if needed (Alberta Auditor General, 2018a).

(ii) Equity Financing

The original equity actually advanced by North West Refining Inc. and CNRL was about \$638 million (DBRS, 2017g).

The terms of the tolling agreements state that APMC and CNRL as toll payers will pay a return on this equity until the equity is repaid (also required under the terms of the tolling agreements). The terms of the tolling agreements also state that this original equity amount was to increase by accruing a 10 per cent rate of return from the date of advance until April 2013. At that date, APMC and CNRL agreed to advance funds by way of subordinated debt, and the rate of return on equity was reduced from 10 per cent to five per cent. As a result, at Nov. 30, 2013, the original equity financing by North West Refining Inc. and CNRL had funded and accrued equity of approximately \$824 million. This equity will continue to earn a five per cent return until it is repaid as set out in the tolling agreements. The accrued five per cent return will increase the value of the funded and accrued equity to about \$1 billion on June 30, 2018 (Alberta Auditor General, 2018b).

The interesting thing to note is that the equity investors are treated as being entitled to a guaranteed return on their investment, which is unusual for normal equity investments.

(iii) Senior Debt Financing

The senior secured debt consists of bonds issued to the public (mostly large institutions), plus a senior credit facility with financial institutions such as banks. The notes to CNRL's financial statements in the past three years show the following tranches of senior bonds:

Senior Bonds

Tranche	Amount, Cdn\$M	Interest Rate	Issue Date	Maturity Date
A	\$500	3.20%	2014	2023
B initial	\$500	4.05%	2014	2043
B reopen	\$300	4.05%	2015	2043
C	\$500	2.10%	2015	2021
D	\$500	3.70%	2015	2043
E	\$500	3.20%	2015	2025
F	\$550	4.25%	2016	2028
G	\$500	4.75%	2016	2036
H	\$500	4.15%	2016	2032
I	\$500	4.35%	2016	2038
J	\$750	2.80%	2017	2026
K	<u>\$750</u>	3.65%	2017	2034
Total	\$6,350			

Senior Credit Facility

The senior credit facility stood at \$2,112 on March 31, 2018, as stated on the notes to the Q1 2018 financial statements of CNRL (2018d). It is reasonable to assume that in order to finance the capital costs to complete the NWR Sturgeon Refinery, the senior credit facility will be drawn to the amount of \$2,650 million when the NWR Sturgeon Refinery commences operations (now scheduled for the fourth quarter of 2018).

The senior credit facility provides flexibility between bond issuances and can be renewed each year during construction such that the facility's maturity will always be between three and four years. In May 2017, DBRS (2017h) stated that the NWR Sturgeon Refinery planned to reduce the \$3.5 billion senior credit facility to approximately \$1.5 billion when the project is near the commercial operating date (now scheduled for the fourth quarter of 2018).

However, CNRL's Q4 2017 financial statements indicated that subsequent to Dec. 31, 2017, the NWR Sturgeon Refinery extended \$2,000 million of the \$3,500 million revolving syndicated senior credit facility to June 2021. The remaining \$1,500 million was extended on a fully drawn non-revolving basis maturing February 2020. This indicates that the senior credit facility will continue to be a source of financing for at least two more years (CNRL, 2017a).

The senior credit facility is assumed to have an interest rate of four per cent.

(iv) Subordinated Debt

As mentioned above, the capital cost of the NWR Sturgeon Refinery increased from \$5.7 billion to \$8.5 billion in early 2014 (DBRS, 2017i).

In order to finance the 20 per cent of this increase that would not be financed by senior debt, APMC and CNRL agreed to advance money in the form of debt that was subordinated to the senior debt. The advance was in the amount of \$350 million each, and had an interest rate of prime plus six per cent. Given the current prime rate in Canada as at May 31, 2018 of 3.45 per cent, this equates to an interest rate of 9.45 per cent. This high interest rate indicated that there was considerable risk associated with this subordinated debt.

APMC and CNRL also agreed to advance more than the \$350 million each if there were no other sources of financing (Alberta Auditor General, 2018c; DBRS, 2017j).

As at March 31, 2018, the amount of subordinated debt advanced by APMC and CNRL was \$432 million each, plus accrued interest of \$111 million, resulting in a total advance of \$543 million for each of APMC and CNRL (2018e).

It is reasonable to assume that in order to finance the capital costs to complete the NWR Sturgeon Refinery, APMC and CNRL will have to advance additional amounts as subordinated debt, and that the accrued interest will continue to increase. A reasonable assumption is that the total amount advanced by each of APMC and CNRL as at the date the NWR Sturgeon Refinery commences operations (scheduled for the fourth quarter of 2018) will be \$450 million each, and that the accrued interest will be \$121 million each. The resulting total of \$571 million each greatly exceeds the \$350 million originally contemplated in 2014.

(v) Final Debt and Equity

Based on the above, it is possible to make a reasonable estimate for the final financing numbers when the NWR Sturgeon Refinery begins to operate in the fourth quarter of 2018. These reasonable assumptions are as follows (all numbers Cdn\$ billion).

Source of Financing	CNRL Q1 2018	Final Reasonable Estimate
Senior Bonds	\$6.350	\$6.350
Credit Facility	\$2.112	\$2.650
Subordinated Debt	\$1.086	\$1.142
Equity	<u>\$1.000</u>	<u>\$1.030</u>
Total	\$10.720	\$11.172

As can be seen, the financing is almost entirely debt. This high proportion of debt would never be possible in a normal refinery that would have to take all the risks associated with capital costs, operating costs and fluctuating crack spreads between the price of bitumen and the price of diesel.

The DBRS (2017k) has rated the senior secured bonds as A low, based on the support the Alberta government has given through APMC as described in the next paragraphs.

(f) Processing Agreements

(i) General Structure

The essence of the allocation of risk between the NWR Sturgeon Refinery as builder and operator, and between APMC and CNRL as the supplier of diluted bitumen feedstock, is contained in the processing agreements (PAs). As will be seen below, the PAs and associated agreements transfer virtually all of the various risks (capital cost and associated financing costs, operating costs, utilization factor, volume and price risk for produced petroleum products and feedstock price risk) from the NWR Sturgeon Refinery to APMC and CNRL.

The PAs entered into by APMC and CNRL with the NWR Sturgeon Refinery are somewhat unusual. Rather than using a specific dollar amount per barrel, the agreements require APMC (75 per cent) and CNRL (25 per cent) to pay a tolling fee that covers all costs of the facility, both capital and operating. This obligation means that APMC and CNRL bear all the risk of an increase in capital costs and any increase in operating costs. The DBRS report confirms in several locations that in its view, the toll payers APMC and CNRL have assumed all the risk for capital costs (including overruns), operating costs and crack spread movements.

(ii) Capital Costs

For capital costs, the PAs require APMC and CNRL to pay all interest and principal repayments for all debt, namely senior bonds, senior credit facility and subordinated debt. The more than doubling of the capital cost has therefore more than doubled the debt financing costs contained in the tolling agreement. The payments for the repayment of the subordinated debt will be made in 120 monthly instalments starting in 2019. The payments of the return of equity will not commence until the subordinated debt has been repaid. These repayments of equity are expected to commence in 2029, and be completed in about 2060. As mentioned above, the equity still outstanding will earn a five per cent return on equity until the equity is repaid (DBRS, 2017l).

(iii) The Debt Service Obligation (DSO)

The PAs contain a provision (referred to as the debt servicing obligation, or DSO) that requires APMC and CNRL as toll payers to pay all financing costs associated with the senior bonds and senior credit facility, including interest, repayment of principal and other financing costs. In effect, it is a guarantee by APMC and CNRL of the senior bonds and senior credit facility issued by the NWR Sturgeon Refinery. This DSO is a key feature DBRS uses in its conclusion to rate the senior bonds at a credit rating (A low) slightly below the province of Alberta (AA high). As DBRS (2017m) pointed out in various parts of its May 2017 rating report:

1. The risk to [senior] bond holders is minimized by the projected cash flow as per the DBRS base case, the priority of debt service and the toll payers' unconditional DSO.
2. These DSOs are intended to be irrevocable and unconditional contractual commitments with NWR in respect of the [NWR Sturgeon Refinery's] debt (APMC (75 per cent) and CNRL (25 per cent)) and are payable whether or not the upgrader-refinery operates. The DSOs also survive the termination of the PAs (or bankruptcy by NWR). The DSO commences at the earlier of COD [the date of first commercial operation] or June 1, 2018, whether or not the upgrader-refinery has achieved COD.
3. The DSO is an unusual level of recourse that is not normally present in a typical project bond.
4. DBRS notes that, according to the PA, the DSO is unconditional and shall not be reduced or affected in any way, including the lack of proceeds of refined products.

The most recent statement as to when the NWR Sturgeon Refinery will commence commercial operations (the commercial operations date or COD) is the fourth quarter of 2018. The processing agreements define the commercial operation date (COD) as occurring when the NWR Sturgeon Refinery operates at a rate of at least 50 per cent of its design capacity of 79,000 barrels per day for a period of at least 30 consecutive days (APMC, 2018a; CNRL, 2018f).

Given the experience of start-up for other similar bitumen processing facilities, it is reasonable to expect that even when commercial operations start, it will likely be several months before the NWR Sturgeon Refinery is able to process 79,000 barrels per day of diluted bitumen, its nameplate capacity. Furthermore, it likely will be at least two months after commercial operation before APMC and CNRL will realize any revenues. The reason for this is that it will take that long before the diluted bitumen can be refined into petroleum products that will be sold and the revenues collected for such sale. Given all this, it is reasonable to assume that APMC and CNRL will receive little if any cash revenue before the end of 2018.

As a result, APMC and CNRL will have to pay interest and principal repayment costs on the senior bonds and the senior credit facility starting on June 1, 2018. Interest payments alone will be in the order of \$25 million per month. The requirement to set aside amounts for principal repayment will be in the order of \$15 million per month. This means that for the seven months after June 1, 2018, APMC and CNRL will have to pay out at least \$280 million (seven months times \$25 million plus \$15 million) in 2018, with little or no revenue to fund these payments. Prior to the COD, any revenues from the current processing of synthetic crude into 15,000 bpd of diesel should be roughly equal to the commissioning, startup and operating costs of the NWR Sturgeon Refinery, and such revenues will be used for that purpose,.

In effect, it is as if one is renting an apartment, but has to start paying rent even though the apartment is not finished and ready for moving in.

Section 13.2(a) of the processing agreement states that APMC and CNRL will only have to start paying all the other components of the tolling fee, namely subordinated debt charges, equity charges and operating costs, when the commercial operation date of the NWR Sturgeon Refinery occurs. This implies that prior to the commercial operation date, all these costs will either continue to be accrued after June 1, 2018, or will be paid out of further draws of cash from the senior credit facility (APMC, 2018b).

(iv) Operating Costs

For operating costs, Schedule 1 of the PAs requires APMC and CNRL to pay all operating costs (APMC, 2018c).

Approximately half are on a flow-through basis (pay 100 per cent of costs as incurred). The other half are on a benchmarked basis (pay 100 per cent of costs as calculated by comparison to external benchmarks for those kinds of costs) (DBRS, 2017n).

One can look at the material published by Husky Energy (2018b) to obtain a reasonable assumption for these cash operating costs. A reasonable estimate is \$10 per barrel operating costs, annual maintenance capex costs of \$20 million, and major turnarounds every four years costing \$80 million.

(v) Other Features of the Processing Agreement

APMC and CNRL are required to pay the tolling fee covering all of the above items even if the NWR Sturgeon Refinery cannot run during a force-majeure event. The ownership of feedstock supplies and refined products always belongs to APMC and CNRL, who will bear all commodity risks. If the gross margin on the sale of petroleum products is insufficient to cover the tolling fee, APMC and CNRL will be required to cover any shortfall amount by cash payment.

While it is not an event of default, if the facility performance of the NWR Sturgeon Refinery falls below a rolling average of 80 per cent for an 18-month period, or throughput falls below 25 per cent for three consecutive months as a result of a site-specific labour disruption, the payment of the return on equity will be suspended (but debt service and operating expenses will continue to be paid) (DBRS, 2017o).

VI. ECONOMIC MODEL

(a) Assumptions for Economic Model

One can use Microsoft Excel to construct an economic model using the above data and assumptions to analyze the economic effect on the toll payers APMC and CNRL. The link to this model is as follows:

<https://www.policyschool.ca/wp-content/uploads/2018/06/Spreadsheet-for-NWR-Economics.xlsx>

1. The following are the base case assumptions:

Feedstock volumes are 79,000 barrels per day of diluted bitumen, petroleum products produced of

40,250 bpd low sulphur diesel

8,790 bpd low sulphur VGO

3,363 bpd of propane/butane

28,266 bpd of diluent

2. Utilization factor of 90 per cent.
3. Revenues are based on volume of various petroleum products multiplied by prices for each petroleum product. The key assumption is the diesel price to WTI price crack spread ratio. The base case assumption is 140 per cent.
4. Feedstock costs for diluted bitumen of US\$18/barrel discount to WTI.
5. WTI price of US\$60/barrel.
6. Assuming US\$60/barrel WTI, this gives a base case diluted bitumen to diesel crack spread of US\$42/barrel calculated as follows:

Discount of WCS to WTI	US\$18/barrel
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140 per cent diesel/WTI means 40 per cent times US\$60/barrel equals	
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	<u>US\$24/barrel</u>
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Total increase in value	US\$42/barrel
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Cdn\$/US\$ FX rate of \$0.80

7. Senior debt financing costs based on issued \$6.35 billion senior bonds and \$2.65 billion senior credit facility and interest rates as issued.
8. Subordinated debt financing costs based on \$1.142 billion subordinated debt and prime plus six per cent interest rate.

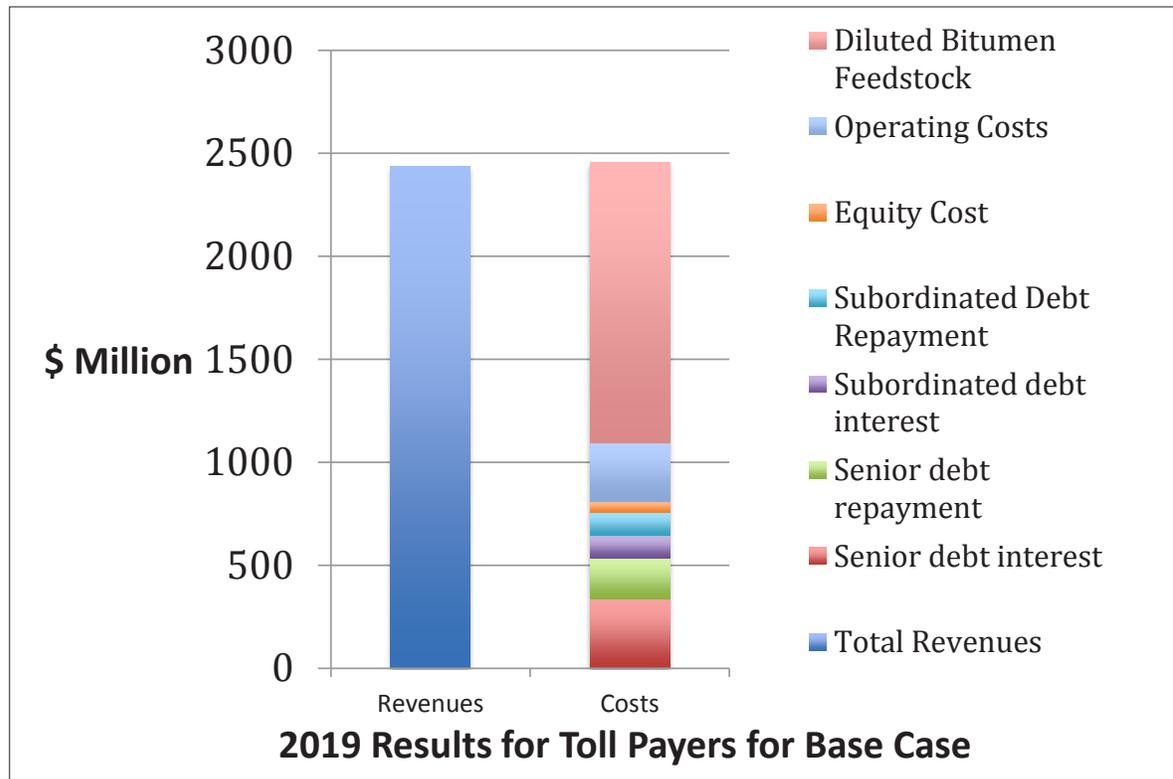
9. Equity outstanding of \$1.03 billion earning a return of five per cent.
10. Cash operating costs of \$10/barrel plus annual maintenance capex of \$20 million and turnaround capex every four years of \$80 million.

(b) Results of Economic Model

(i) Base Case

Using these assumptions, the economic model shows the annual cash flows received by the toll payers APMC and CNRL. The cash flows are the amount that the toll payers would receive as an alternative to just selling their diluted bitumen at the Hardisty WCS price. In other words, it shows the value added (or cost) that occurs as a result of refining the diluted bitumen into petroleum products.

The following chart shows the results of the economic model for 2019 using the base case assumptions. The column on the left shows the revenues from the sale of the various petroleum products such as diesel and other products in the amount of about \$2.4 billion. The stacked column on the right shows all the costs associated with making the petroleum products, namely diluted bitumen feedstock, operating costs and the various financing costs for debt and equity. The total cost amount is slightly greater than \$2.4 billion, resulting in a base case negative cash flow of about \$24 million per year.



The economic model also shows that the results for the 10 years from 2020 to 2030 would be very similar to 2019.

(ii) Market Price Sensitivities

The economic model clearly shows that the revenue amounts will vary greatly if one assumes a change in market conditions, namely the two spread amounts (WCS/WTI discount, or diesel/WTI crack spread). The following table shows the cash flow numbers using the sensitivities outlined above.

	130% diesel/WTI	140% diesel/WTI	150% diesel/WTI
US\$15/barrel	-\$221 million	-\$121 million	-\$22 million
US\$18/barrel	-\$124 million	-\$24 million	+\$75 million
US\$21/barrel	-\$26 million	+73 million	+172 million

It is interesting to view these two crack spread assumptions in light of the recent dispute between Alberta and British Columbia regarding the expansion of the Kinder Morgan Trans Mountain pipeline. The objective of such expansion is to get more diluted bitumen to Asian markets and therefore reduce the WCS/WTI discount. Conversely, if Alberta were to reduce the shipment of petroleum products to British Columbia, as it had indicated it might do, this action would divert petroleum product sales from British Columbia to the remaining Western Canada market, and therefore would likely reduce the price of diesel sold in that market. Either outcome would reduce the cash flows to APMC and CNRL.

(iii) Other Sensitivities

Reducing the assumption for WTI pricing from US\$60/barrel to US\$50/barrel would reduce the cash flow by \$78 million per year. The reason for the reduction is that the reduction in WTI pricing would reduce the diluted bitumen to diesel crack spread in actual dollars per barrel.

As a further sensitivity, each drop of 10 per cent in utilization factor would result in a decrease in cash flow of \$90 million per year. The reason for the drop is that the drop in utilization factor would result in a reduced production of petroleum products and therefore reduced revenue. The costs would not be reduced as much, since all financing costs must be paid regardless of production volumes.

In an extreme case, there is the possibility that the NWR Sturgeon Refinery would cease operations permanently and go bankrupt. This would mean no revenues, and no cash operating costs. If this event ever occurs, the DSO would require APMC and CNRL to pay the approximately \$9 billion of principal on senior bonds and senior credit facility plus the interest on such principal. As stated, there would be no revenue to offset these costs, and therefore the loss to APMC and CNRL would be much greater.

(c) Conclusions of Economic Model

The economic model shows that the cost/benefit analysis for APMC and CNRL is very dependent on the state of market prices for diluted bitumen and diesel. The higher the

spread between these two prices, the better the economics – the lower the spread, the worse the economics.

VII. REACTION TO NWR STURGEON REFINERY

(a) Background

The NWR Sturgeon Refinery has been the subject of discussion for several years. The *Globe and Mail* contained the following extract:

“Earlier this year, North West Upgrading chairman Ian MacGregor said the refinery project would have never got off the ground without Alberta government involvement ... On Wednesday, Wildrose party finance critic Rob Anderson said he wants to see more bitumen processing in Alberta. But he said when a project is only viable because a government participates, ‘then that should be a huge red flag for people’” (Cryderman, 2013).

(b) Review by Alberta Auditor General in February of 2018

According to the *Calgary Herald*, “Just last week, Alberta’s auditor general complained that the Crown corporation overseeing the project, the Alberta Petroleum Marketing Commission, is keeping Albertans in the dark about the financial risks of the project. ‘I’ll be blunt, Albertans are not being fully informed about this very significant endeavour,’ said Merwan Saher who, tellingly, is rarely blunt about anything” (Thomson, 2018a).

Review by Alberta Auditor General in February of 2018

On Feb. 22, 2018, the Auditor General of Alberta issued a specific report on the NWR Sturgeon Refinery. Among its many findings were the following:

1. Albertans should also receive sufficient public reporting on this arrangement to be able to keep current with the risks they assume and the benefits they receive.
2. Given the nature of the agreement, the level of public reporting from the APMC is not good enough. The agency is acting as steward of the province's resources, and Albertans have a right to know how it is using those resources. They are currently not receiving that information.
3. The agency has an obligation to report on its agreements to Albertans, whose resources it uses.
4. In 2011, the estimated NPV for the government was a range of \$200 million to \$700 million over the life of the project. As of early 2017, that estimate covering the 30-year term is now under \$200 million.
5. Potential benefits in the public sector are more complicated because they may involve policy objectives, such as job creation and economic diversification. The APMC needs to work with the Department of Energy to determine what risks and benefits of this arrangement could be reported, when to report them publicly and who should report what.
6. The APMC, after it begins to supply bitumen and receive proceeds from the sale of refined products, will be reporting the profit or loss as a result of the agreement. Albertans will then get an annual picture of the financial results over the life of the agreement.
7. Because of the structure of the NWRP arrangement, there is no plausible scenario where it would make financial sense to pull out of it. Albertans' resources are therefore committed. Strong oversight and risk management are consequently all the more important.
8. An analysis of lessons learned from the Sturgeon refinery contracting processes could be very important to help with any future decisions on contracts for value-added activities, including a processing agreement related to phase two of the Sturgeon refinery.
9. We recommend that the Alberta Petroleum Marketing Commission prepare a business plan and an annual report that are made publicly available to Albertans. The APMC must be able to demonstrate it has given appropriate consideration to the nature and extent of information it will share with Albertans.

(c) Reaction of the NWR Sturgeon Refinery

The backers of the NWR Sturgeon Refinery have proposed future expansions in two phases, each involving an additional processing capacity of 50,000 barrels of bitumen per day. It is also reasonable to expect that the Alberta government should make a careful review of the go-forward economics of future tolling arrangements before agreeing to support future phases 2 and 3 of the NWR Sturgeon Refinery.

A recent *Financial Post* article stated:

“A proposal to build the second phase of the Sturgeon Refinery, the first new refinery in Alberta in the last 30 years, is being withdrawn as the company behind the project evaluates the changing economic environment facing the oil industry ... ‘We think it’s the right thing to do,’ North West Refining president and CEO Ian MacGregor told the *Financial Post* on Friday, adding that he expected construction of the first phase to finish by the summer ...

“Canadian Natural has taken a similar wait-and-see approach: ‘I think our plan here is let’s just make sure the plant runs effectively and efficiently. And when we see that, then we’ll make a decision whether or not to participate in any kind of expansion, if it makes sense,’ Canadian Natural Resources Ltd. executive vice-chairman Steve Laut said on an earnings call Thursday” (Morgan, 2018).

(d) The Alberta Government’s Reaction

The government of Alberta recently made the following announcement, according to the *Calgary Herald*:

“On Monday, [Premier Rachel] Notley announced, among other things, a \$1-billion plan to help spur the partial upgrading of bitumen in Alberta. The idea is to put up to \$800 million in loan guarantees and \$200 million in grants over a period of eight years to entice companies to open facilities to turn heavy bitumen into a lighter product for easier shipment through pipelines (if only she could get more pipelines built, that is. And while we’re in parentheses, we could argue this is another example of how we aren’t diversifying away from our fossil fuel economy but trying to add value to it).

““This will attract two to five partial upgrading facilities in Alberta representing up to \$5 billion in private investment and create 4,000 jobs in construction,’ said an optimistic government background paper” (Thomson, 2018b).

Chris Varcoe (2018) offered another comment in the *Calgary Herald*:

“But grand plans to move Alberta up the energy value chain don’t mention the risks involved, such as the province’s ill-fated experience with the bi-provincial upgrader in the 1990s. The province invested \$404 million in capital costs in the project at Lloydminster, only to sell its stake four years later for only \$32 million ... Nor do they mention Alberta’s involvement in the Sturgeon Refinery, which saw the project’s price tag jump from \$5.7 billion to \$9.4 billion.”

Bloomberg reported that: “Alberta’s government’s C\$1 billion-dollar pledge (US\$780 million) will help support the construction of smaller and cheaper varieties of upgraders. The so-called partial upgraders would process the sticky oil just enough so that it can flow freely through pipelines without adding ultra-light condensate. The government expects that as many as five private investors will infuse about C\$5 billion in the sector ... Since

partial upgrading would reduce or eliminate the need for the condensate that makes up about a third of the heavy oil-sands crude, it would free up pipeline space and produce a grade of oil that's easier to refine and more valuable than the heavy grades produced" (Tuttle, 2018).

VIII. CONCLUSIONS AND LESSONS FOR FUTURE GOVERNMENT ASSISTANCE

In essence, it would appear that the NWR Sturgeon Refinery could be viewed as Alberta's equivalent of the Quebec and federal governments' investment in Bombardier, or the federal and Newfoundland government's support of the Muskrat Falls electric project in Newfoundland. The federal and Quebec governments have given financial assistance to Bombardier in order to support their industrial strategy of having an aerospace industry in Quebec. The federal and Newfoundland governments have given financial assistance to the Muskrat Falls project to support their industrial strategy of having more electrical generation in Newfoundland and Labrador. The government of Alberta has given financial assistance to the NWR Sturgeon Refinery in order to support its strategy of having bitumen refined in Alberta. This note has attempted to put a dollar amount on the cost of that financial support.

Specifically, the cash flows to APMC and CNRL will be slightly negative (minus \$24 million) in 2019. The variation in the market prices for WCS/WTI discount and diesel/WTI crack spreads could change this number for 2019 from -\$221 to +\$172 million. In addition, a failure to achieve a 90 per cent utilization factor will reduce the 2019 cash flows by \$90 million for each 10 per cent reduction in utilization factor. The government of Alberta bears 75 per cent of these risks and returns.

In each case, it is the government's prerogative to make such a choice. But it should also be the government's obligation to explain and justify such choice.

As long ago as the 1970s when Peter Lougheed was premier, various Alberta governments have tried different mechanisms to encourage investment with the goal of diversifying Alberta's economy. These mechanisms include government subsidies, guarantees and other methods to encourage investment (often from the private sector) when ordinary market forces and economics are not sufficiently robust to cause such investment to occur.

This paper has attempted to put numbers on one such government initiative designed to assist a private sector investment. The purpose of doing so is to improve the debate over the merits of such government incentives. It is hoped that it might provide a template for the assessment of the merits of such government assistance to investments in future projects, preferably before the project is approved rather than after.

The recommended lessons for government would be as follows:

1. Avoid entering into open-ended guarantee agreements that expose governments to unlimited risks for things such as capital cost overruns, operating cost risks, guaranteed returns on debt and equity, and commodity market risks.

2. The corollary of recommendation one is to limit government aid to a fixed and capped amount. Do several variations to show sensitivity for key assumptions.
3. Make such numbers public.
4. In particular, governments should explain why such assistance is needed, and should explain what larger government benefits will result, and more importantly, the dollar amount of the benefit. For example, if job creation is a benefit, the government should state the cost per job created.

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