AECOM

Appendix A

Business Case Analysis

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1. Business Case

The growing demand for oil worldwide, coupled with expanding production in the Alberta Oil Sands region, has created the need for more transportation infrastructure to transport oil and oil products from Northern Alberta to export gateway locations within Canada and to or through the United States. At the same time, proposed oil pipeline projects are facing strong opposition from many stakeholders and have been delayed, which could put some pipeline projects in jeopardy. Without additional transportation capacity, future development of Western Canadian oil production, and the economic spin-off benefits that come with that development, in the form of jobs, royalties, tax revenue, will be negatively impacted.

Given the considerable uncertainty around the realization of each of the major new pipeline projects, due to regulatory approvals, the opposition of major stakeholders (governments, aboriginal groups, environmental groups), and environmental factors, it is worthwhile considering a few scenarios in which one or more of the announced pipelines are either not approved or are developed with significant delays. This would result in a substantial shortage of transportation capacity for Alberta crude oil output. This business case examines a rail transportation option that has the advantage of more rapid delivery, lower inventory costs, negligible diluent costs and significantly increased capacity to transport raw bitumen at a comparable toll rate per barrel that is currently accepted by the Industry.

This business case uses a discounted cash flow (DCF) model to determine the all in cost per barrel of transporting bitumen by rail from Alberta to Alaska. The model includes all loading and unloading costs at the rail terminals, all capital and operating costs, and factors in a reasonable internal rate of return to calculate the minimum price per barrel for the rail transportation of bitumen. The costs used in this business case were obtained from the engineering Pre-Feasibility Study.

The DCF model considers both capital and operational costs for the haulage of bitumen in loaded rail tank cars from a loading facility in Alberta to an unloading facility in Alaska, and the return haulage to Alberta of the empty rail tank cars. The business model uses a pricing methodology where costs are fully recovered and the model yields indicative estimates of the total cost per barrel from the perspective of the shipper (the ShipperCo case) and a total price (or toll) per barrel from the perspective of the railway (the RailCo case). The costs and tolls for the scenarios have been calculated for the haulage of 1.0 million barrels per day (mbpd) and 1.5 mbpd for an operations period of 20 years for the railway. The per barrel cost to ship undiluted bitumen from Alberta to Alaska are shown in the table below.

	ShipperCo	RailCo
	$/Barrel Cost (in 2013 $)	
Scenario 20 Year Duration 1.0 mbpd	$9.96	$9.49
Scenario 20 Year Duration 1.5 mbpd	$8.14	$7.66

1.1 Market Context

This section of the report provides an overview of the market conditions for Alberta oil sands production over the current period through to 2040. Section 1.2 begins with an overview of the demand for energy worldwide and by region, as well as by fuel type, with a focus on the demand for petroleum and crude oil. Section 1.2.1.3 reports the expected production profiles for crude oil and particularly for bitumen output from the Alberta oil sands. These production profiles are based on expected oil prices which are discussed in section 1.2.1.4. Section 1.2.1.5 examines the economic feasibility of the oil sands output profiles by comparing oil prices to estimated costs of production for various oil sands extraction techniques.

1.2 Market Conditions for Alberta Oil Sands Production

1.2.1 Current and Prospective Demand and Supply Conditions for Crude Oil

1.2.1.1 Demand for Energy

The most recent outlook from the US International Energy Outlook 2013 (*IEO2013*) indicates that world energy consumption is expected to grow at a rate of 1.5% per year over the period from 2010 to 2040. However, there is a considerable disparity in growth rates between mature energy consumers, such as Canada, US and Japan – where energy demand is expected to be flat or barely growing (e.g., 0.3% annual growth for the US) – and developing countries where energy demand continues to grow at rates above 2% per year, despite the recent slowdown in growth prospects for China and other emerging markets. These growth rates mean that energy demand in countries such as China and India is expected to more than double by 2040 relative to 2010. In the mature economies of the OECD, energy demand is expected to be only about 17% higher in 2040.

Table 1 Energy Consumption for Selected Countries Worldwide, Reference Case

	(quadrillion BTUs)							
	2010	2015	2020	2025	2030	2035	2040	CAGR
	History	Forecast						2010-40
Canada	13.5	14.2	14.8	15.6	16.5	17.3	18.2	1.0%
United States	97.9	97.3	100.5	101.8	1023.0	103.9	107.2	0.3%
Japan	22.1	21.7	22.5	23.0	23.0	22.9	22.2	0.0%
Total OECD	242.3	244.1	254.6	262.7	269.2	276.1	284.6	0.5%
Brazil	13.7	14.9	16.5	17.8	19.9	22.3	25.4	2.1%
China	101.2	132.2	159.0	180.9	198.9	213.3	219.9	2.6%
India	24.4	27.5	32.1	37.2	42.6	48.7	55.0	2.7%
Total non-OECD	281.7	327.9	375.3	417.7	460.0	501.0	535.1	2.2%
Total World	523.9	572.0	629.8	680.4	729.2	777.1	819.6	1.5%
Source: International Energy Outlook 2013, Table A1, p. 179								
Note: Total OECD refers to all OECD member countries as of September 1, 2012, including Mexico, Chile and Israel.								

The demand for energy is driven by a number of factors including economic growth, energy prices and the energy efficiency of different sectors as well as policies and regulations. The energy consumption forecast in the previous table is the central or "reference forecast" for the IEO2013 and is based on the assumption that GDP growth worldwide will come in at 3.6% per year in real terms (i.e., after inflation), with OECD countries at 2.1% growth and non-OECD countries at 4.7% growth.[1] The reference case also assumes that world oil prices rise from $81 per barrel in 2010 to $106 per barrel in 2020 and $163 in 2040 (all prices in 2011 $ and for Brent crude, the global benchmark for crude oil).[2] The *IEO2013* forecasts do "not incorporate prospective [changes in] legislation or policies that might affect energy markets" (p.1).

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[1] *IEO2013 also includes consumption forecasts for high and low economic growth scenarios as well as for high and low oil prices.*

[2] *According to IEO2013, these oil price assumptions are based on "current judgment regarding exploration and development costs and accessibility of oil resources" and on the assumption that "OPEC producers maintain their share of the market and will schedule investments in incremental production capacity so that OPEC's oil production will represent between 39 and 43 percent of the world's total petroleum and other liquids production over the projection period" (p.25).*

1.2.1.2 Energy Demand by Fuel Type

The following table shows that consumption of all energy sources is expected to rise over the thirty year period through to 2040. However, petroleum is the slowest growing energy source, exhibiting a growth rate of only 0.9% per year average. This is consistent with the *IEO2013* view that oil prices over the forecast period will continue to rise and remain high relative to historical experience. Nevertheless, petroleum and other liquid fuels are the largest energy source and accounted for one-third of world energy consumption in 2010 (and 28% of energy consumed in 2040). According to the *IEO2013* report, petroleum use is expected to rise in the transportation and industrial sectors, but decline in the buildings and electric power sectors.

Table 2 World Energy Consumption Fuel Type, Reference Case

	(quadrillion BTUs)							
	2010	2015	2020	2025	2030	2035	2040	CAGR
	History	Forecast						2010-40
Petroleum	176.1	185.5	194.7	202.1	210.9	221.1	232.6	0.9%
Natural gas	116.8	124.2	136.0	148.5	162.6	177.4	191.3	1.7%
Coal	147.4	164.6	180.3	196.0	207.9	216.7	219.5	1.3%
Nuclear	27.3	30.4	37.9	44.3	49.5	53.5	57.2	2.5%
Other	56.2	67.3	81.0	89.5	98.3	108.5	119.1	2.5%
Total	523.9	572.0	629.8	680.4	729.2	777.1	819.6	1.5%

Source: International Energy Outlook 2013, Table A2, p. 181.

Note: Petroleum and other liquid fuels includes a full array of liquid product supplies. Petroleum liquids include crude oil and lease condensate, natural gas plant liquids, bitumen, extra-heavy oil, and refinery gains. Other liquids include gas-to-liquids, coal-to-liquids, kerogen, and biofuels.

In regional terms, petroleum demand is expected to grow most rapidly in non-OECD Asia (i.e., China and India), where growth is forecast at an average of 2.3% per year through to 2040, as shown in the following table:

Table 3 Petroleum Liquids Consumption by Region, Reference Case

	(quadrillion BTUs)							
	2010	2015	2020	2025	2030	2035	2040	CAGR
	History	Forecast						2010-40
OECD Americas	46.4	45.9	46.4	46	45.8	46.1	47	0.0%
OECD Europe	30.6	27.9	28.4	28.4	28.7	28.9	29.1	-0.2%
Total OECD	92.8	90.6	91.4	91	90.9	91.4	92.3	0.0%
Non-OECD Asia	40.6	46.2	53.2	59.7	65.6	72.6	80.1	2.3%
Total Non-OECD	83.3	94.9	103.3	111.1	119.9	129.7	140.3	1.8%
Total World	176.1	185.5	194.7	202.1	210.9	221.1	232.6	0.9%
Source: International Energy Outlook 2013, Table A2, pp. 180-181.								
Note: Petroleum and other liquid fuels includes a full array of liquid product supplies. Petroleum liquids								
include crude oil and lease condensate, natural gas plant liquids, bitumen, extra-heavy oil, and refinery								
gains. Other liquids include gas-to-liquids, coal-to-liquids, kerogen, and biofuels.								

Petroleum consumption in the mature OECD economies is expected to be flat over the same period. The only other areas of growth are non-OECD Europe and Eurasia[3], where petroleum consumption is expected to grow at 1.8% per year.

1.2.1.3 Production Forecasts for Canadian Oil Sands

The commercial viability of oil sands production depends on many factors, including supply-side factors such as the ability to secure funding, capital and operating costs for extraction and transportation costs, as well as demand-side factors such as prices for extracted bitumen and for synthetic crude oil (SCO)[4], derived from the initial upgrading of the bitumen. The production estimates for oil sands shown in the following figure suggests producers remain cautiously optimistic about the prospects for substantial increases in oil sands production despite the challenges, which range from securing capital funding to overcoming regulatory delays, labor shortages, transportation bottlenecks and environmental concerns.

There are several sources for long-term production forecasts for the Canadian oil sands. For consistency, we begin with the *IEO2013* forecast for petroleum and other liquids in the following table.

[3] Non-OECD Asia includes such countries as Russia, Croatia, Romania and Ukraine.
[4] According to CERI (2013: 57), all bitumen extracted by mining techniques and a portion of in situ production is upgraded to SCO.

Table 4 Production Forecast for Petroleum and other Liquid Fuels[1] by Selected Regions, Reference Case

	(million barrels per day)								
	2010	2011	2015	2020	2025	2030	2035	2040	CAGR
	History		Forecast						2010-40
Canada	3.6	3.7	4.7	5.1	5.6	5.9	6.1	6.2	1.8%
United States	9.4	9.8	12.2	12.8	12.1	11.5	11.6	11.7	0.7%
OECD Europe	4.6	4.2	3.7	3.4	3.1	2.9	3.1	3.6	-0.8%
Non-OECD Asia	8.2	8.1	8.1	8.1	8.4	8.7	8.6	8.7	0.2%
Brazil	2.5	2.5	3.3	4.4	5.6	7.0	7.5	7.7	3.8%
Total World	86.6	86.8	92.0	96.6	100.2	104.4	109.4	115.0	0.9%
Worldwide production increment (cumulative)[2]			5.4	10.0	13.6	17.8	22.8	28.4	
Canada share of production increment			20%	15%	15%	13%	11%	9%	

Source: International Energy Outlook 2013, Table G1, p. 247, based on projections from the EIA, Generate World Oil Balance Model (2013).

Notes: (1) Petroleum and other liquid fuels includes a full array of liquid product supplies. Petroleum liquids include crude oil and lease condensate, natural gas plant liquids, bitumen, extra-heavy oil, and refinery gains. Other liquids include gas-to-liquids, coal-to-liquids, kerogen, and biofuels.

(2) Increment in production relative to 2010.

The *IEO2013* forecast shows that Canada has one of the highest average growth rates in production at 1.8% over the thirty-year period, and is only superseded by Brazil at 3.8% per year. The US production forecast peaks in 2020 and declines slightly thereafter. Production in OECD Europe (primarily North Sea oil) declines by close to 1% per year and volumes in non-OECD Asia (primarily China and India) remain relatively flat at 0.2% growth per year. It is also worth noting that Canada accounts for a modest share of the worldwide increase in production (relative to 2010 levels) – at less than 20% for most of the period.

This forecast is for the reference case – consistent with the reference case for the consumption forecast in Tables 1 to 3, but is based on a separate sub-model known as the Generate World Oil Balance Model (GWOB), which provides a “bottom-up projection of world liquids supply based on current production capacity, planned future additions to capacity, resource data, geopolitical constraints and prices” (p. 297). It is important to note that the GWOB projections take into account the impact of oil prices on both the demand and supply levels but it does not take into account the availability of transportation routes to market.

A second source of long-term production forecasts is the Canadian Association of Petroleum Producers (CAPP). The table below shows a detailed breakdown of Canadian crude oil production from the June 2013 CAPP publication *Crude Oil: Forecast, Markets & Transportation*. The table shows that conventional crude oil sources are expected to be either flat or declining through to 2030. However, the rapid growth in oil sands production is expected to dwarf the decline in conventional oil output. The table also shows raw bitumen figures for the two main types of extraction methods – mining and in situ production, with the latter expected to grow almost twice as fast as mining. The oil sands production figures in the table are based on a survey of oil sands producers rather than any explicit modeling of supply, demand and oil prices. Total Canadian production in the following table is broadly consistent with the petroleum production figures for Canada in the previous table.[5]

[5] *Note that petroleum and liquids in Table 4 is a broader category that includes crude oil as one of its component liquids.*

Table 5 CAPP Production Forecast for Crude Oil, Canada and Oil Sands

	(million barrels per day)							
	2012	2013	2014	2015	2020	2025	2030	CAGR
	History	Forecast						2012-30
Western Canada Conventional[1]	1.2	1.3	1.3	1.4	1.4	1.4	1.4	0.8%
Eastern Canada Conventional[1]	0.2	0.2	0.2	0.2	0.2	0.2	0.1	-4.5%
Oil Sands	1.8	2.0	2.2	2.3	3.2	4.5	5.2	6.1%
Total Canadian production	3.2	3.5	3.7	3.9	4.9	6.0	6.7	4.1%
Oil Sands Raw Bitumen[2]								
Mining	0.9	1.0	1.1	1.1	1.4	1.8	1.9	4.0%
In Situ	1.0	1.1	1.2	1.3	2.0	2.8	3.6	7.3%
Total Oil Sands (Raw Bitumen)	1.9	2.1	2.3	2.4	3.4	4.7	5.5	6.0%

Source: CAPP Crude Oil: Forecast, Markets and Transportation, Table B1, p. 36.
Note: (1) Includes condensates.
(2) Raw bitumen production figures are a combination of upgraded crude oil and bitumen and therefore incorporate yield losses from integrated upgrader projects. Production from off-site upgrader projects included in production numbers as bitumen.

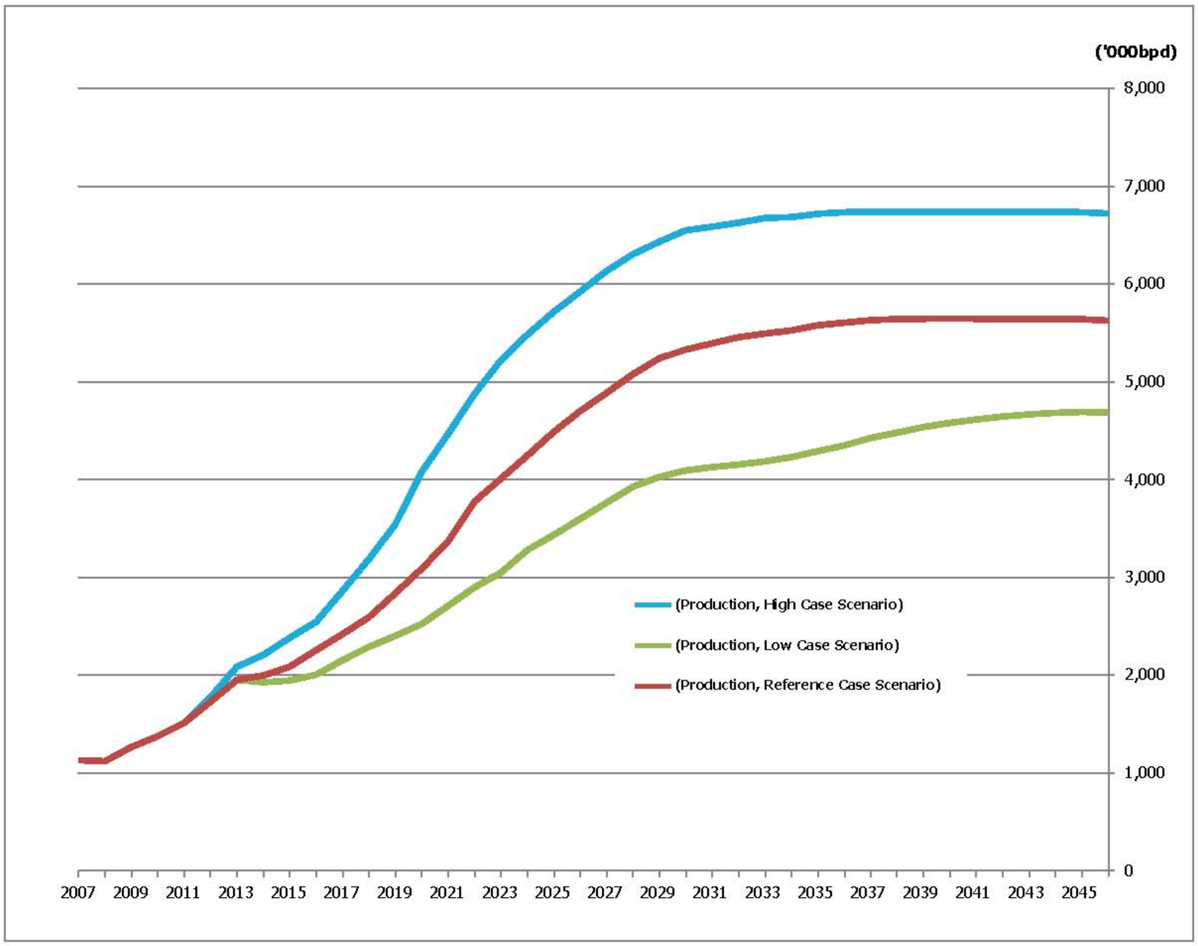
A third source of production forecasts is the Canadian Energy Research Institute (CERI), which has recently published its oil sands output forecasts in *Canadian Oil Sands Supply Costs and Development Projects (2012-46)*. This forecast is a based on a bottom-up estimate of production on a project-by-project basis, using data provided by oil sands producers and other publicly available information and including projects already on stream, those under construction, approved, awaiting approval and announced.

In the High Case scenario, oil sands production from mining and *in situ* thermal and solvent extraction methods (excluding primary and enhanced oil recovery which accounted for only 0.2 million barrels per day (mbpd) in 2011) is expected to grow from 1.5 mbpd in 2011 to more than four times the production rate at 6.7 mbpd in 2046, representing a compound annual growth rate (CAGR) of 4.4% per year. However, this scenario is based on the premise that high oil prices will more than offset the effects of production cost inflation and that capacity will be available to meet the transportation requirements for crude exports and for access to production inputs such as diluent and natural gas for *in situ* extraction methods (CERI 2013: 44-45). In the Low Case scenario, oil sands production triples from 2011 levels to 2046, exhibiting a CAGR of 3.3% per annum. This scenario is based on the premise that worldwide economic growth is relatively low by historical standards, that energy demand is flat and that environmental policy concerns dominate energy policy-making (CERI 2013: 43). The Reference Case scenario sees oil sands output growing at an average rate of 3.8% per year to yield a production rate of 5.3 mbpd by 2030 and 5.6 mbpd by 2046. According to CERI (2013: 45), “this scenario is in line with expectations for pipeline capacity additions (assuming they all come on stream), and it is possible that the labour and capital markets in Alberta will be capable of handling this expansion without causing undue stress on the local economy”.

Table 6 CERI Canadian Oil Sands Production Forecast[1]

	(million barrels per day)				
	2011	2020	2030	2046	CAGR
	History	Forecast			2011-46
High Case	1.5	4.1	6.5	6.7	4.4%
Reference Case	1.5	3.1	5.3	5.6	3.8%
Low Case	1.5	2.5	4.1	4.7	3.3%

Source: CERI (2013): *Canadian Oil Sands Supply Costs and Development Projects (2012-46)*, May 2013, pp. 46-47; AECOM Analysis.
Note: (1) Excludes primary bitumen production.

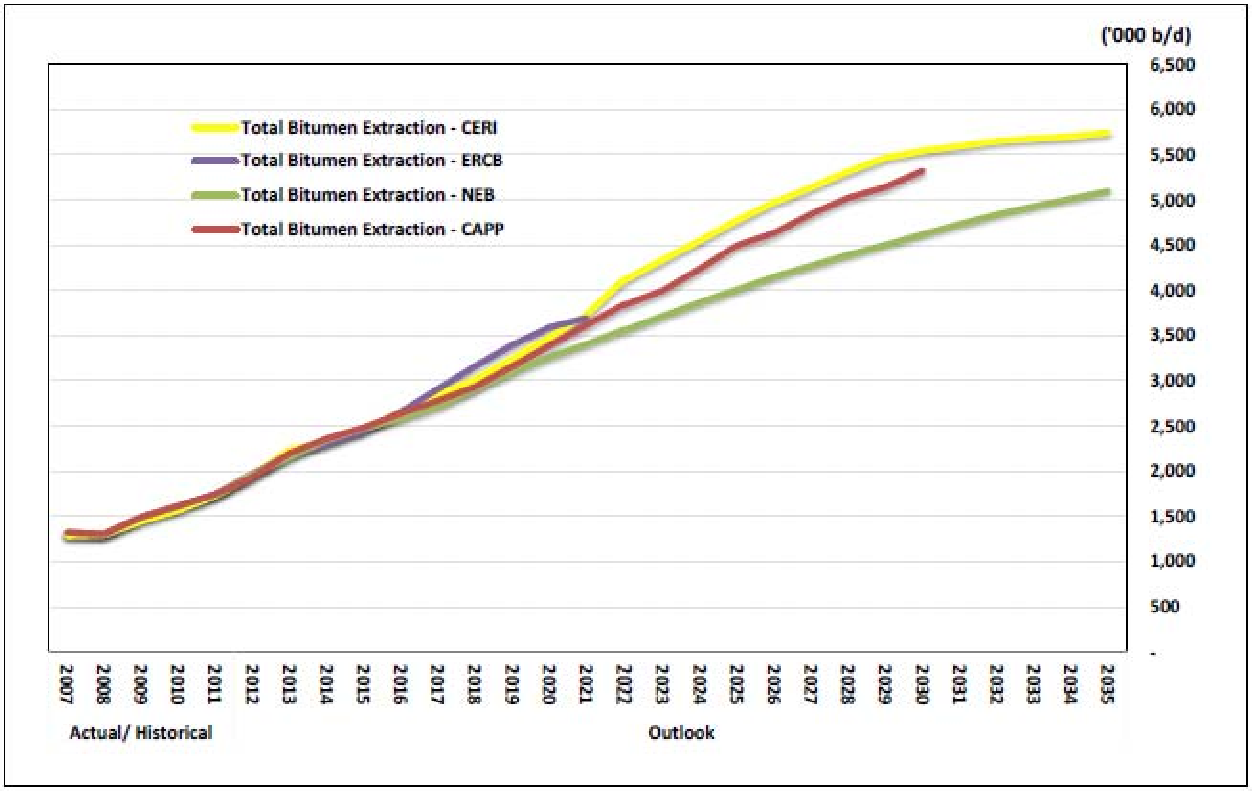


Source: CERI, CanOils

Figure 1 CERI Bitumen Production Projections

Source: CERI 2013: 47. These figures elaborate on those presented in Table 6 above.

CERI (2013) also compares its reference forecast for bitumen production with that from other sources, notably CAPP, the National Energy Board (NEB) and the provincial regulator, the Energy Resources Conservation Board (ECRB), as shown in the following figure. The CERI reference forecast is consistent with other forecasts through to 2021 but is slightly higher in the latter part of the forecast period due to the "inclusion of some announced projects which were not included in the other forecasts" (p. 57). In the remainder of the business case analysis, we rely on the CERI Reference Case forecast for bitumen production.



Source: CERI, ERCB, CAPP, NEB

Figure 2 Bitumen Production Forecasts Compared

Source: CERI 2013: 57.

1.2.1.4 Pricing Trends for Crude Oil

The bitumen production forecasts in Figure 2 above depend critically on oil sand producers' view of oil prices over the time frame relevant to their individual project investments and specifically on the prices they can command for either raw bitumen or Synthetic Crude Oil (SCO).

The figure below shows the three scenarios for Brent crude oil prices which underlie the energy consumption and production forecasts developed by the US Energy Information Administration (EIA). The Reference scenario shows that oil prices rising at a somewhat lower rate than the average rates seen since 2000.

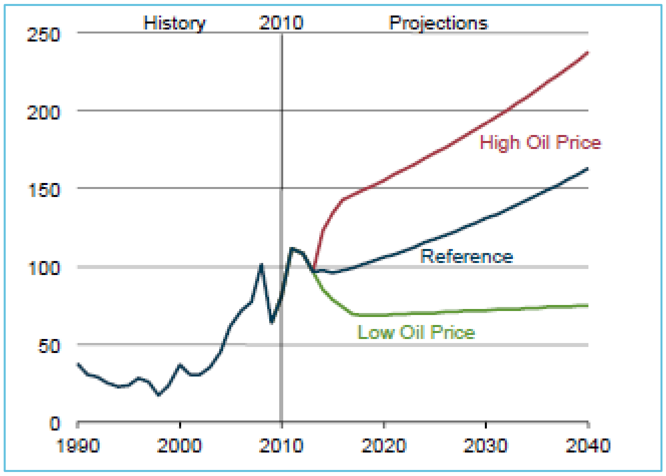


Figure 3 EIA Scenarios for Brent Crude Oil Prices

Source: EIA2013: 25.

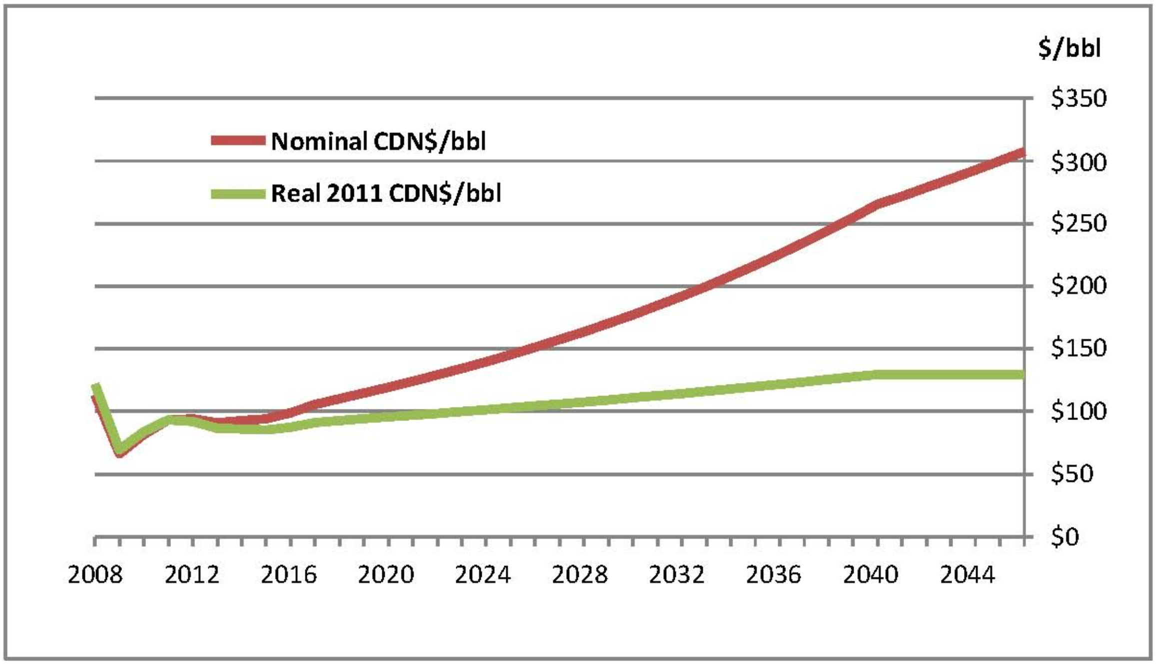
The EIA reference forecast for Brent crude is also broadly consistent with the oil price forecast which serves as the basis for the CERI Reference forecast, as shown in Figure 4. The following figure shows the oil price (likely for Brent, though not explicitly stated) in Canadian currency (both in nominal terms and in 2011 $), with Canadian and US dollars assumed at par.

It is important to recognize that Canadian heavy crude oils, such as Western Canadian Select (WCS), the benchmark Canadian heavy crude oil, have historically commanded prices significantly lower than crudes of similar quality in the US Gulf Coast. This has been attributed to limited pipeline connections from the Alberta oil sands to the Pacific Coast or beyond PADD II in the US Midwest; and to the different market conditions in the areas where these crude oils are priced.[6] In addition, in recent years, the spread between the US benchmark West Texas Intermediate (WTI) and the global benchmark Brent crude has been as high US $23 or more per barrel, although it has narrowed to less than $10 in recent months due to new pipeline and crude-by-rail terminals coming online as well as higher production rates at US refineries.[7][8] Notwithstanding these considerations, CERI (2013) notes that the reference forecast for oil prices in the following figure is “in a favourable range for oil sands proponents to develop their projects” (p. 10). This is supported by their analysis of the supply costs for Alberta crude oil discussed in the next section.

[6] *For example, see a note by Argus http://media.argusmedia.com/~/media/Files/PDFs/White%20Paper/Argus%20WCS%20at%20Cushing.pdf.*

[7] *EIA, “Spread narrows between Brent and WTI crude oil benchmark prices”, August 5, 2013. See http://www.eia.gov/todayinenergy/detail.cfm?id=12391.*

[8] Market Realist, “*Why the WTI-Brent oil spread is at its widest level since March”,* November 5, 2013. See http://marketrealist.com/2013/11/wti-brent-spread-widest-level-since-march/



Source: EIA, CERI.

Figure 4 CERI Reference Case Oil Price Forecast

Source: CERI 2013: 10 Adapted from EIA.

1.2.1.5 Cost of Production for Canadian Oil Sands Resources

The CERI (2013) report developed estimates of the supply costs and breakeven market prices required for oil sands production based on alternative extraction methods. Specifically, supply costs refer to the price per barrel required to recover all capital spending (initial and sustaining capital), operating costs, royalties, taxes and earn a reasonable return on investment (a fixed, 10% real rate of return is assumed). The supply costs are reported in the following figure at field gate prices (i.e. excluding transportation and blending costs), (with all prices in 2011 Canadian dollars). The following figure shows the lowest supply costs are for primary recovery at $30.32/bbl., followed by SAGD at $47.57/bbl. – both in situ techniques. Integrated mining and upgrading has the highest supply cost at $99.02/bbl. followed by stand-alone mining at $68.30/bbl.

CERI then calculated the WTI-equivalent supply costs after making adjustments for transportation and blending costs. These are $58.61/bbl. for primary recovery, $77.85 for SAGD, $103.16 for integrated mining and upgrading and $99.49 for stand-alone mines. In other words, if producers believe that WTI benchmark prices will exceed the appropriate break-even point over the production period for their project, then that project should be economically attractive to the extent that the assumptions used are representative of the project economics.

	Primary Recovery 10% ROR (a)	SAGD 10% ROR (a)	Mining & Upgrading 10% ROR (a)	Mining 10% ROR (a)
Fixed Capital (Initial & Sustaining)	$14.31	$19.87	$51.03	$32.00
Operating Working Capital		$0.45	$1.01	$0.69
Fuel (Natural Gas)		$3.23	$2.55	$1.60
Other Op. Costs (Fixed, Variable, Elec)	$8.38	$11.44	$23.62	$17.00
Royalties	$6.40	$8.83	$12.89	$12.76
Income Taxes	$1.23	$2.98	$7.20	$4.31
Emissions Compliance Costs		$0.73	$0.65	$0.40
Abandonment Costs		$0.03	$0.07	$0.05

Source: CERI

Figure 5 CERI Field Gate Supply Costs for Bitumen/SCO, Reference Case

Source: CERI 2013: 32

Some of the key assumptions used for the supply cost analysis were as follows:

- 10% real (12.5% nominal) rate of return on investment
- A USD $15/bbl. differential between light and heavy crude, since blended bitumen/SCO is a heavy crude, while the WTI benchmark is a light crude
- Exchange rate parity between C$ and US$
- Other assumptions regarding taxation and royalties are stated in CERI (2013), chapter 3.

It is also worthwhile noting that the supply costs in the previous figure were calculated as point estimates – i.e. one for each of the four extraction methods. In practice, there is a distribution of supply costs across projects for each type of extraction method due to differences in the quality of reserves, their geographic location and the financial structure of the project. However, to the extent that the supply costs in previous figure are deemed roughly representative, these are helpful in providing a guide as to the rationale for the prospective decisions of oil sands producers to invest in projects to bring new oil sands output on stream, particularly through in situ techniques such as SAGD.

1.2.2 Current and Prospective Routes to Market

This section is intended to compare current and announced transportation projects for exporting Alberta crude oil to the additional transportation capacity required to export the projected increase in oil sands output. Section 1.2.3 reviews the current transmission pipeline capacity for crude oil out of Alberta as compared to the current output of crude oil from Western Canada. Section 1.2.4 reviews the capacity and timing of the proposed pipeline transmission projects for transporting crude oil output out of Alberta combined with an assessment of potential additional rail capacity. Section 1.2.5 provides an assessment of the additional pipeline transmission capacity required to transport the incremental output of crude oil by 2020 and by 2030, taking into account the diluent requirements to enable the flow of non-upgraded bitumen through pipelines. The last section compares the capacity of the announced pipeline transportation projects to the pipeline capacity requirements implied by the projected increase in Alberta oil sands output and discusses potential scenarios for the realization of the announced pipeline projects.

1.2.3 Current Crude Oil Transportation Routes to Markets outside Alberta

There are currently four transmission pipelines carrying crude oil and other petroleum products out of the Alberta oil sands, with a maximum capacity of 3.5 mbpd as shown in following table.[9] The following table also shows the Enbridge Bakken Expansion project from North Dakota to Manitoba, because this capacity of 145,000 bpd – intended to allow Bakken oil through the mainline network – competes with oil products from the Alberta Oil Sands.

Table 7 Current Pipeline Capacity for Crude Oil out of Alberta Oil Sands

Pipelines	Destination(s)	Capacity (millions bpd)	Start of Operations	Notes:
Enbridge Mainline	Ontario, US Midwest, Montana, North Dakota	2.5	1950	Some US production enters Enbridge network and competes for capacity with Alberta crude.
Enbridge Bakken Expansion project	Berthold, ND to Cromer, MN	-0.145	2013 (March)	Additional capacity for Bakken crude to enter Mainline for destinations in midwest, Eastern Canada.
KM Trans Mountain	Edmonton to BC, Washington refineries and to Westridge terminal for export	0.3	1953	Sole pipeline capacity to West Coast. Oversubscribed since at least 2010.
Spectra Express-Platte	Hardisty to Caspar, WY	0.28	1997	Insufficient downstream capacity constrains actual throughput (192k in 2012)
TransCanada Keystone	Hardisty to Steele City, NE	0.59	2010	Cushing extension came online Feb 2011. About 530k bpd of capacity is contracted
Total Current Transmission Capacity		3.525		Effective capacity is less due to maintenance operations and "operational pressure restrictions on certain lines and physical constraints at terminals on the system" CAPP (2013: 21)
Source: CAPP (2013), AECOM analysis.				

9 In addition to the transmission pipeline capacity in Table 7, there is also a network of feeder pipelines which take crude products from the oil sands to termini in Edmonton and Hardisty (and pentanes/condensate northbound to the extraction sites). Total southbound feeder capacity is about 2 million bpd according to a recent analysis (Dr. Malcolm Cairns "Crude Oil by Rail: Parts I and II" CTRF June 11 2013).

In addition to pipeline capacity, there is also currently some capacity to move crude oil by rail out of the Alberta oil sands. Most of the recent movement of crude oil by rail has occurred as a result of the increase in crude oil production from the Bakken Shale formation in North Dakota. According to the Association of American Railroads, 365,000 carloads of crude oil and petroleum products were shipped by rail in the first half of 2013. The EIA estimates that this represents 1.37 mbpd (based on 700 barrels per carload) and that crude oil accounts for about 700,000 barrels per day.[10] This figure includes both US crude oil and imported crude oil (i.e. crude oil from Canada). According to another source, Canadian crude oil shipments by rail may be as high as 150,000 bpd.[11] According to CAPP (2013: 37), total crude oil production in Western Canada – including conventional output – supplied to transmission (or trunk) pipelines amounted to 3.2 mbpd in 2012. This was expected to increase to 3.43 mbpd in 2013. This suggests that the current pipeline network is already operating at or very close to full capacity, with some allowance made for the fact that actual operating capacity of transmission pipelines is likely less than the 3.525 mbpd noted in the previous table. It is also clear that additional transportation requirements are increasing being handled by rail car movements.

1.2.4 Prospective Crude Oil Transportation Routes to Markets Outside Alberta

Proposed transmission pipelines for delivering crude oil from Alberta to other markets in Eastern Canada, the US Gulf Coast and to the West Coast for export to Asia would add at least 2.1 mbpd of export capacity by the end of 2017, assuming all the projects are realized by the targeted in-service dates.

Table 8 Propose Pipeline Capacity for Crude out of Alberta Oil Sands

(millions barrels per day)				
Pipelines	**Destination(s)**	**Capacity**	**Target date:**	**Notes:**
Enbridge Mainline (Clipper Expansion)	Superior, WI	-0.12	2014 Q1	Approved by regulator (for Bakken crude to enter Mainline at Superior WI)
Enbridge Mainline (Clipper Expansion)	Superior, WI	-0.23	2016 Q1	Additional capacity for Bakken crude to enter Mainline at Superior, WI
Enbridge Northern Gateway Project	Kitimat, BC	0.525 +	2017 Q4	Includes condensate pipeline. NEB to issue recommendation Dec. 2013
KM Trans Mountain Expansion	BC	0.59	2017 Q4	Twinning of existing pipeline
TransCanada Keystone XL	Nebraska	0.830 +	2015	New Presidential permit application filed in May 2012; awaiting approval
TransCanada Energy East	Quebec, New Brunswick	0.525 to 0.850	2017 Q4	Conversion of gas pipeline (Sask to Qc) and construction of new pipelines (Hardisty to Sask.; Montreal to Saint John, NB)
Total Proposed Transmission Capacity		2.12 +		
Source: CAPP (2013), AECOM analysis.				

In addition to proposed pipeline transmission capacity, there is also evidence of proposed investments in rail terminals and orders for oil tank cars, which indicate that additional crude is likely to be transported by rail. The following figure is a list of additional rail terminal investments complied by ARC Financial Corp., which shows that additional rail transportation capacity for crude oil out of Alberta could amount to 700,000 barrels per day by 2015.

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[10] *EIA "Rail delivery of US oil and petroleum products continues to increase but pace slows" Today in Energy, July 10 2013. http://www.eia.gov/todayinenergy/detail.cfm?id=12031*

[11] *Jackie Forrest, IHS as cited in The Globe and Mail, "Oil Industry Watches as Policy Makers Face Rail Questions", July 8 2013.*

Table 9 Rail Terminal Oil Capacity Additions (2012 to 2015)

Location	Capacity (bpd)
Hardisty, AB	120,000
Unity, SK	90,000
Edmonton, AB (Bruderheim)	70,000
Northgate, SK	70,000
Lashburn, SK	60,000
Cromer, MB	60,000
Southall, SK	52,000
Edmonton, AB	40,000
South Cheecham, AB	32,000
Lynton, AB (Fort McMurray)	25,000
Lloydminister, SK	23,000
Instow, SK	18,000
Unity, SK	15,000
Tilley, AB	9,000
Whitecourt, AB	9,000
Wainwright, AB	6,000
Sexsmith, AB	6,000
Lloydminister, SK	3,000
Total	**708,000**

Source: ARC Financial Corp. "Canadian Rail Projects Tallying Up to Keystone XL Capacity" Energy Charts. Accessed Aug 12, 2013. http://arcfinancial.com/research/energy-charts/canadian-rail-projects-tallying-up-to-keystone-xl-capacity

Given the uncertainty regarding the development and timing of the in-service dates of the major pipeline projects additional rail capacity will be required for the additional crude oil output.

1.2.5 Transmission Pipeline Requirements for Exporting Forecast Increases in Alberta Crude Oil Production

Crude oil output is expected to increase by 1.6 mbpd by 2020 and by 3.8 mbpd by 2030 (compared to 2011), according to CERI forecast noted above. Using a base year of 2012 and the CAPP production forecast, the increase in output is expected to be 1.5 mbpd by 2020 and 3.5 mbpd by 2030.

Table 10 shows that the incremental oil sands output of 1.5 mbpd by 2020 would require additional pipeline transportation capacity of 1.91 mbpd, based on assumptions about the mix between non-upgraded bitumen, which requires diluent to flow through the pipeline network, and SCO, which does not. The 3.5 mbpd of additional output by 2030 would require 4.59 million barrels of additional transportation capacity.

Table 10 Transmission Pipeline Capacity Requirements for Incremental Oil Sands Output

	2020	2030	Sources:
(millions barrels per day)			
Incremental Oil Sands Output	1.5	3.5	CAPP
Non-upgraded bitumen (%)	70%	80%	CERI (2013: 60)
SCO (%)	30%	20%	CERI (2013: 60)
Non-upgraded bitumen	1.05	2.8	
Diluent/barrel required	0.39	0.39	CERI (2013: 63) assuming Pentanes Plus/Condensate
Transport requirement	1.46	3.89	
SCO	0.45	0.7	
Total Pipeline Capacity Requirement	**1.91**	**4.59**	
Source: AECOM Analysis			

These estimates of additional pipeline transportation capacity are conservative because it does not account for additional capacity utilization required to handle maintenance operations; nor does it account for capacity required for inbound diluent; nor for transport requirements for inputs into the oil sands extraction process, such as substantial natural gas requirements for in situ production. The above analysis does not account for any pipeline capacity released due to any decline in the transportation requirements of conventional crude oil output.

1.2.6 Summary and Potential Scenarios for Consideration

The results of this section indicate that all the announced pipeline transmission projects must be realized in order to meet the transportation requirements for additional oil sands output by 2020. Table 10 shows that at least 1.91 mbpd of additional capacity is required to transport the additional crude oil output of 1.5 mbpd using pipelines by 2020. Table 8 showed that the four major announced pipeline projects would provide for at least 2.12 mbpd of additional pipeline transmission capacity, after taking account of the Alberta pipeline export capacity which is likely to be taken up by oil movements from the Bakken shale formation. If any one of the major pipeline projects is either not approved or not brought into service by 2020, this would results in a shortage of pipeline transmission capacity, given current projections for oil sands output.

Even if all the pipeline projects are brought into service at the announced target in-service dates, there is a need in the interim (i.e. through to 2015) for additional transportation capacity because the oil sands output continues to grow while the current pipeline transmission network is already operating at capacity. This additional demand for transportation capacity of crude oil output is being met by additional rail capacity. Rail cars are already being used to transport a substantial share of the oil output from the Bakken shale formation, where there is a limited pipeline network. Recent investments in oil handling terminals in Alberta indicate the rail cars will also be used to move increased oil sands output.

Given the considerable uncertainty around the realization of each of the major new pipeline projects, due to both uncertainties related to regulatory approvals, including obtaining a Presidential Permit in the case of the TransCanada Keystone XL project, as well as uncertainties resulting from the opposition of other major stakeholders (governments, aboriginal groups, environmental groups), it is worthwhile considering a few scenarios in which one or more of the announced pipelines are either not approved or are developed with significant delays. For example, one potential scenario may see a Presidential Permit not issued to the TransCanada Keystone XL, which would delay the project well beyond the 2015 start date and possibly abort it entirely. A second scenario would see the Enbridge Northern Gateway Project not realized due to opposition from one or more stakeholder groups. If either of these two scenarios were realized, there would be a substantial shortage of transportation capacity for Alberta crude oil output, although one that could potentially be addressed by incremental investments in rail handling capacity. The current conventional rail transportation options would entail higher shipping costs per barrel for shippers, despite the advantages of more rapid transportation (and hence, lower inventory costs), lower diluent costs and less transportation capacity required to transport 100% raw bitumen (or even railbit, a 85:15 ratio of bitumen to diluent).

If both scenarios were to occur (i.e. both the Keystone XL (KXL) and the Northern Gateway (NG) projects are not realized), it is unlikely that incremental investments in conventional rail termini alone could meet the shortage of transportation capacity – which would amount to at least 1.35 million barrels per day. This view is based not only on the announced investments in rail termini, but also other third party assessments.[12] Even this combined scenario (no KXL, no NG, yet additional new rail termini) would still require the realization of the Kinder Morgan Trans Mountain and the TransCanada Energy East projects.

1.3 Methodology

1.3.1 Cost of Service Model

The business case for the Alberta to Alaska Railway is based broadly on the cost-of-service methodology used by the National Energy Board (NEB) and other regulators to set pipeline tolls. It is one contributing foundation for market based pricing in the railroad sector. This methodology was selected for two reasons:

- To allow potential shippers to compare the per barrel tolls on the Alberta to Alaska Railway to the per barrel transportation costs incurred using alternative modes of transportation, such as new or existing pipelines (or existing railway services), and

- To allow potential investors in the Alberta to Alaska Railway to understand the tolls which will be required in order to fully recover capital and operating costs over the useful economic life of the asset, assuming certain throughput assumptions regarding bitumen shipments.

According to the NEB, the cost-of-service model is an approach which sets pipeline tolls at the rate at which the capital and operating costs of the regulated pipeline can be fully recovered.

> “a pipeline company's tolls are set to provide investors with the opportunity to recover costs and earn a reasonable return on their investment in the pipeline. To set tolls, the cost of service and throughput are forecast for a forward test year. The cost of service is made up of operating expenses, depreciation, return on capital, and income and other taxes. The Board allows, but does not guarantee, a pipeline company the opportunity to earn an approved rate of return”

[12] *For example, Cairns (2013) estimates that rail could move an additional 600,000 to 800,000 bpd without major new rail infrastructure investments.*

NEB "The Regulation of Traffic, Tolls and Tolls"
http://www.neb-one.gc.ca/clf-nsi/rthnb/whwrndrgvrnnc/rgltntrffctllstrffs2007-eng.html#s5
(accessed 7 November 2013)

In 1995, the NEB revised the cost of service methodology by instituting a "uniform rate of return on common equity based upon the forecast interest rate for long-term Government of Canada bonds, plus a risk premium". The NEB also established "a procedure for annual adjustment of the rate of return on equity".[13]

Our cost-of-service approach follows the spirit of the full cost-recovery methodology described above, but it uses a market-based estimate of the cost of equity required to fund the Alberta to Alaska Railway rather than the NEB allowed return on common equity.

The next part of the methodology section describes the Discounted Cash Flow (DCF) model which is used to derive the price per barrel required to recover the full capital and operating costs of the new railway. The DCF model is structured to capture all the capital, operating and maintenance costs which will be incurred for the transportation of bitumen from the Alberta oil sands through to the TAPS pipeline in Alaska, including handling costs at both ends. The model does not capture the cost of transporting the bitumen through the TAPS pipeline to the Port of Valdez but alternatives were considered in Section 1.6.6.

The ShipperCo version of the model captures the full capital and operating costs borne by the shipper for transportation costs between Alberta and the Alaska TAPS pipeline, regardless of whether these costs and the associated risks are the responsibility of the carrier (i.e. the railway), the shipper or a third-party service provider. Hence, the transit price per barrel derived from the ShipperCo model is that required to fund the full transmission costs for the relevant volume of bitumen and is comparable to the per barrel pipeline tolls for an equivalent pipeline transporting an equivalent volume of bitumen. However, a like-for-like comparison with pipeline transportation costs also requires taking into account the cost of the diluent and the capital and operating costs required for the additional handling and pipeline/storage capacity needed to transport the diluent to the bitumen injection point.

The RailCo version of the model is designed to convey the business case for the Alberta to Alaska Railway company, based on the assets which it is expected to own, operate and maintain; and the associated operating and maintenance costs for which it will bear responsibility. For example, the tank cars used for transporting bitumen would most likely be owned by the shippers or by a third party. As a result, the capital required for these tank cars is not included in the RailCo version of the DCF model. This means that the transit price per barrel derived from the RailCo model is the actual price that would form the basis of a long-term contract between RailCo and committed shippers (although the contract could be structured with changing prices over time and/or different prices for shippers with different volume and other contractual commitments).

1.3.2 Discounted Cash Flow Model

A discounted cash flow (DCF) model was developed to estimate the $/barrel cost and price to transport bitumen by railway from Alberta to Alaska. The DCF model considers both capital (Capex) and operational (Opex) costs for the haulage of bitumen in loaded rail tank cars from a loading facility in Alberta to an unloading facility in Alaska, and the return haulage to Alberta of the empty rail tank cars. As explained in section 1.3.1, the business model being evaluated is one in which pricing is set in a manner in which Capex and Opex are fully recovered through an appropriate cost of capital. This requirement is the underlying principle on which the DCF model has been built and how the financial analysis has been conducted.

The DCF model yields indicative estimates of the total cost per barrel from the perspective of the shipper, which is referred to as the ShipperCo case. Similarly the model yields indicative estimates of total price (or toll) per barrel

[13] *http://www.neb-one.gc.ca/clf-nsi/rthnb/whwrndrgvrnnc/rgltntrffctllstrffs2007-eng.html#s5.*

from the perspective of the railway, which is referred to as the RailCo case. The costs and tolls for the scenarios have been calculated for the haulage of:

- 1.0 M barrels per day (mbpd), and
- 1.5 M barrels per day

The ShipperCo cost/toll and RailCo cost/toll estimates are shown for 2013 (nominal Canadian (CAD) dollars) and have been calculated on a pre-interest and tax basis.

Furthermore the DCF model is based on the following general project timeline:

- Year 1 – 2: Environmental Assessment
  (i.e., 2 years)
- Year 3 – 5: Construction
  (i.e., 3 years)
- Year 4 – 6: Delivery of Rolling Stock
  (i.e., 2 years but phased in over Construction and Ramp-Up)
- Year 6 – 7: Ramp-Up
  (i.e., for 2 years: 33% of targeted bitumen volume in Year 6 and 67% of targeted bitumen volume Year 7 are transported)
- Year 8 - ...: Full Operations
  (i.e., for 18 years in which each year 100% of the targeted volume of 1.0 mbpd or 1.5 mbpd are transported).

The project life is 25 years consisting of 5 years for environmental assessment and construction work and 20 years for railway operations in which 2 years are a ramp-up period and the remaining 18 years are run to transport 100% of targeted bitumen volume. At the end of operations the DCF analysis includes a salvage value for:

- Track
- Signals & Communication
- Rolling Stock & Equipment
- Facilities.

The salvage value is based on the remaining portion of the total economic life of the assets.

To estimate the ShipperCo costs and the RailCo tolls, the DCF model is based on a number of parameters for the Alberta to Alaska Railway. These parameters are shown by scenario in the following table:

Table 11 DCF Scenario Parameters

		ShipperCo		RailCo	
	Scenario (mbpd)	**1.0**	**1.5**	**1.0**	**1.5**
Project Life Years	Environmental Assessment	2	2	2	2
	Construction	3	3	3	3
	Ramp Up	2	2	2	2
	Full Operations	18	18	18	18
	Total Duration	**25**	**25**	**25**	**25**
Financial	Debt/Equity Ratio	65% Debt / 35% Equity			
	Cost of Debt	6.0%			
	Cost of Equity	12.2%			
	Weighted Average Cost of Capital	8.2%			
	Cost Escalation (Capex & Opex)	3.0%			
	Price Escalation ($/Barrel change year-over-year)	2.0%			
	Salvage Value Based on Total Life in Years	Track		50	Years
		Signals & Communications		25	Years
		Rolling Stock & Equipment		25	Years
		Facilities		25	Years
Operations	Loaded Train Starts per Day	8	12	8	12
	Operational Days per Year	329	329	329	329
	Total Loaded Train Starts per Year	2,632	3,948	2,632	3,948
	Total Barrels Hauled Per Year (Millions)	**329**	**494**	**329**	**494**
	Total Barrels Hauled for Duration (Millions)	**6,248**	**9,372**	**6,248**	**9,372**

These scenarios represent the Base Cases for ShipperCo and RailCo. The Base Cases for these scenarios use a weighted average cost of capital (WACC) of 8.2% as the pre interest and tax discount rate for the DCF analysis. Whereas the model assumes that input costs escalate over time at 3% per year and $/barrel prices escalate at 2% per year.

Each of the Base Cases were run so that the ShipperCo costs and RailCo tolls were set at a level that returns a net present value (NPV) of zero and assured an internal rate of return (IRR) or discount rate of 8.2%. These Base Cases were supplemented with a number of additional runs. These additional runs changed one parameter at a time so that the sensitivity of the estimates to various changes could be better appreciated.

Table 12 DCF Sensitivity Analysis

DESCRIPTION		CHANGES TO BASE CASE
BASE CASE	Expected	NA
COST	Capex High	+27.47%
	Capex Low	-25.79%
	Opex High	+10.00%
	Opex Low	-10.00%
	Capex & Opex High	+27.47%/+10.00%
	Capex & Opex Low	-25.79%/-10.00%
FINANCIAL	Less Salvage	0.00%
	Discount Rate High	10.2%
	Discount Rate Low	6.2%
	Cost Escalation High	4.0%
	Cost Escalation Low	2.0%
	Price Escalation High	3.0%
	Price Escalation Low	1.0%
RISK	Capex Risk High	+50.00%
	Opex Risk High	+50% Fuel

The table above shows the changes that were made in order to perform a Sensitivity Analysis. The various inputs and outputs of the runs conducted are shown and discussed in the following sections.

1.4 ShipperCo Financial Analysis

1.4.1 DCF Analysis

The Capex and Opex inputs for the ShipperCo 1.0 mbpd DCF analysis are shown in the following tables:

Table 13 ShipperCo 1.0 mbpd Capex Costs $2013 Millions CAD

DISCIPLINE	Low 5%	Expected	High 95%	ExpectedCost per Mile
ORIGINAL SCOPE ITEMS				
PART A: TRACK	$1,470	$1,890	$2,349	$1.25
PART B: EARTHWORKS	$5,067	$7,714	$10,559	$5.09
PART C: BRIDGES & STRUCTURES	$2,278	$2,975	$3,676	$1.96
PART D: TUNNELS	$226	$241	$254	$0.16
PART E: SIGNALS & COMMUNICATIONS	$270	$447	$645	$0.29
PART F: ROLLING STOCK & EQUIPMENT	$1,338	$1,536	$1,732	$1.01
PART G: FACILITIES	$625	$708	$794	$0.47
PART H: ENVIRONMENT	$166	$228	$294	$0.15
PART I: ENABLING WORKS	$182	$233	$277	$0.15
PART J: OTHERS	$2,752	$3,398	$4,108	$2.24
SUB TOTAL	**$14,373**	**$19,368**	**$24,688**	**$12.78**
ADDITIONAL SCOPE ITEMS				
NO ITEMS	$0	$0	$0	$0.00
	$0	$0	$0	$0.00
	$0	$0	$0	$0.00
	$0	$0	$0	$0.00
SUB TOTAL	**$0**	**$0**	**$0**	**$0.00**
GRAND TOTAL:	**$14,373**	**$19,368**	**$24,688**	**$12.78**
RANGE	**-25.79%**	**Expected**	**27.47%**	

Table 14 ShipperCo 1.0 mbpd Opex Costs in $2013 Millions CAD

DISCIPLINE	Low	Expected	High	Expected Cost per Mile
ORIGINAL SCOPE ITEMS				
LABOUR	$93	$104	$114	$0.07
OPERATING SUPPLIES	$1	$2	$2	$0.00
MAINTENANCE MATERIALS	$410	$456	$501	$0.30
SERVICES OR G&A	$1	$1	$1	$0.00
DUST SUPPRESSION WATER	$6	$7	$8	$0.00
POTABLE WATER	$0	$0	$0	$0.00
DIESEL FUEL	$570	$633	$696	$0.42
SUB TOTAL	**$1,082**	**$1,202**	**$1,322**	**$0.79**
ADDITIONAL SCOPE ITEMS				
NO ITEMS	$0	$0	$0	$0.00
	$0	$0	$0	$0.00
	$0	$0	$0	$0.00
	$0	$0	$0	$0.00
SUB TOTAL	**$0**	**$0**	**$0**	**$0.00**
GRAND TOTAL:	**$1,082**	**$1,202**	**$1,322**	**$0.79**
RANGE	-10.00%	**Expected**	10.00%	

The parameters and variables used in the ShipperCo 1.0 mbpd DCF Base Case for 20 years are shown in the following table:

Table 15 ShipperCo 1.0 mbpd Base Case 20 Year Parameters

LIFE OF OPERATIONS IN YEARS	20					
OPERATIONS		Year 6	Year 7	Year 8	Year 9	...
		33%	66%	100%	100%	
OPERATING DAYS PER YEAR	336					
BITUMEN BARRELS PER DAY (Millions)	1					
BITUMEN BARRELS PER YEAR (Millions)	336	111	222	336	336	336
BITUMEN TRAINS PER DAY	8					
BITUMEN TRAINS PER YEAR	2,688	887	1,774	2,688	2,688	2,688

DEBT/EQUITY STRUCTURE	
DEBT %	65%
EQUITY %	35%
TOTAL	**100%**
COST OF DEBT	6.0%
COST OF EQUITY	12.2%
WEIGHTED AVERAGE COST OF CAPITAL (DISCOUNT RATE)	**8.2%**
OPERATING RATIO	77%
REVENUE = COST PLUS	30%
OPERATING INCOME MARGIN (EBITA)	23%
$/BARREL RATE ESCALATION PER YEAR	2%
SCENARIO COSTS	Expected

CAPEX	$2013 Millions	Year 1	Year 2	Year 3	Year 4	Year 5	Year 6	Total	Escalation
ORIGINAL SCOPE ITEMS									
PART A: TRACK	$1,890			$630	$630	$630	$0	$1,890	3.0%
PART B: EARTHWORKS	$7,714			$2,571	$2,571	$2,571	$0	$7,714	3.0%
PART C: BRIDGES & STRUCTURES	$2,975			$992	$992	$992	$0	$2,975	3.0%
PART D: TUNNELS	$241			$80	$80	$80	$0	$241	3.0%
PART E: SIGNALS & COMMUNICATIONS	$447			$149	$149	$149	$0	$447	3.0%
PART F: ROLLING STOCK & EQUIPMENT	$1,536			$0	$0	$768	$768	$1,536	3.0%
PART G: FACILITIES	$708			$236	$236	$236	$0	$708	3.0%
PART H: ENVIRONMENT	$228	$59	$59	$37	$37	$37	$0	$228	3.0%
PART I: ENABLING WORKS	$233			$78	$78	$78	$0	$233	3.0%
PART J: OTHERS	$3,398			$1,133	$1,133	$1,133	$0	$3,398	3.0%
SUB TOTAL	**$19,368**	**$59**	**$59**	**$5,905**	**$5,905**	**$6,673**	**$768**	**$19,368**	
ADDITIONAL SCOPE ITEMS									
NO ITEMS	$0	$0	$0	$0	$0	$0	$0	$0	3.0%
	$0	$0	$0	$0	$0	$0	$0	$0	3.0%
	$0	$0	$0	$0	$0	$0	$0	$0	3.0%
	$0	$0	$0	$0	$0	$0	$0	$0	3.0%
SUB TOTAL	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	
TOTAL	**$19,368**	**$59**	**$59**	**$5,905**	**$5,905**	**$6,673**	**$768**	**$19,368**	

OPEX	$2013 Millions	Year 6	Year 7	Year 8	Year 9	...	Escalation
		33%	66%	100%	100%		
ANNUAL MAINTENANCE - ORIGINAL SCOPE ITEMS							
LABOUR	$104	$34	$68	$104	$104	$104	3.0%
OPERATING SUPPLIES	$2	$1	$1	$2	$2	$2	3.0%
MAINTENANCE MATERIALS	$456	$150	$301	$456	$456	$456	3.0%
SERVICES OR G&A	$1	$0	$1	$1	$1	$1	3.0%
DUST SUPPRESSION WATER	$7	$2	$5	$7	$7	$7	3.0%
POTABLE WATER	$0	$0	$0	$0	$0	$0	3.0%
DIESEL FUEL	$633	$209	$418	$633	$633	$633	3.0%
SUB TOTAL	**$1,202**	**$397**	**$793**	**$1,202**	**$1,202**	**$1,202**	
ANNUAL MAINTENANCE - ADDITIONAL SCOPE ITEMS							
NO ITEMS	$0	$0	$0	$0	$0	$0	3.0%
	$0	$0	$0	$0	$0	$0	3.0%
	$0	$0	$0	$0	$0	$0	3.0%
	$0	$0	$0	$0	$0	$0	3.0%
SUB TOTAL	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	
TOTAL	**$1,202**	**$397**	**$793**	**$1,202**	**$1,202**	**$1,202**	

SALVAGE VALUE	$2013 Millions	ECONOMIC LIFE IN YEARS TOTAL	AFTER SALVAGE	ANNUAL APPRECIATION
SALVAGE VALUE				
PART A: TRACK	$1,134	50	30	3.0%
PART E: SIGNALS & COMMUNICATIONS	$89	25	5	3.0%
PART F: ROLLING STOCK & EQUIPMENT	$307	25	5	3.0%
PART G: FACILITIES	$142	25	5	3.0%
TOTAL	**$1,672**	WEIGHTED ESCALATION		3.0%

The results for the ShipperCo 1.0 mbpd Base Case DCF are shown in the following table and figure:

Table 16 ShipperCo 1.0 mbpd Base Case DCF 20 Years

CALCULATIONS DCF $Millions	Year

SCENARIO

LIFE OF OPERATIONS IN YEARS	20
COSTS	Expected
DISCOUNT RATE	8.2%
PROJECT OPERATING RATIO (OR)	74%
PROJECT OPERATING INCOME	26%
2013 PRICE $/BARREL	$9.96
ANNUAL $/BARREL ESCALATION	2%

Calculate OR For NPV = $0

Year	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24	25	TOTAL
	Phase 1		Phase 2			Phase 4	Phase 5																			
					Phase 3																					
	Env Assessment		Construction			Ramp-Up	Operations for Total of 20 Years																			
					Rolling Stock																					
OPERATIONS																										
BITUMIN BARRELS PER YEAR (Millions)						111	222	336	336	336	336	336	336	336	336	336	336	336	336	336	336	336	336	336	336	6,381
BITUMEN TRAINS PER YEAR						887	1,774	2,688	2,688	2,688	2,688	2,688	2,688	2,688	2,688	2,688	2,688	2,688	2,688	2,688	2,688	2,688	2,688	2,688	2,688	51,045
REVENUES PRICE $/BARREL	$10.16	$10.37	$10.57	$10.79	$11.00	$11.22	$11.45	$11.67	$11.91	$12.15	$12.39	$12.64	$12.89	$13.15	$13.41	$13.68	$13.95	$14.23	$14.52	$14.81	$15.10	$15.40	$15.71	$16.03	$16.35	
REVENUE						$1,244	$2,538	$3,923	$4,001	$4,081	$4,163	$4,246	$4,331	$4,418	$4,506	$4,596	$4,688	$4,782	$4,877	$4,975	$5,074	$5,176	$5,279	$5,385	$5,493	$87,777
SALAVAGE VALUE																									$3,501	$3,501
TOTAL REVENUES						**$1,244**	**$2,538**	**$3,923**	**$4,001**	**$4,081**	**$4,163**	**$4,246**	**$4,331**	**$4,418**	**$4,506**	**$4,596**	**$4,688**	**$4,782**	**$4,877**	**$4,975**	**$5,074**	**$5,176**	**$5,279**	**$5,385**	**$8,994**	**$91,278**
COSTS																										
CAPEX																										
ORIGINAL SCOPE ITEMS																										
PART A: TRACK			($688)	($709)	($730)																					($2,128)
PART B: EARTHWORKS			($2,810)	($2,894)	($2,981)																					($8,684)
PART C: BRIDGES & STRUCTURES			($1,084)	($1,116)	($1,149)																					($3,349)
PART D: TUNNELS			($88)	($90)	($93)																					($271)
PART E: SIGNALS & COMMUNICATIONS			($163)	($168)	($173)																					($503)
PART F: ROLLING STOCK & EQUIPMENT					($890)	($917)																				($1,808)
PART G: FACILITIES			($258)	($266)	($274)																					($797)
PART H: ENVIRONMENT	($61)	($62)	($40)	($41)	($42)																					($247)
PART I: ENABLING WORKS			($85)	($87)	($90)																					($262)
PART J: OTHERS			($1,238)	($1,275)	($1,313)																					($3,826)
SUB TOTAL	($61)	($62)	($6,452)	($6,646)	($7,736)	($917)																				($21,874)
ADDITIONAL SCOPE ITEMS																										
NO ITEMS																										
SUB TOTAL																										
TOTAL CAPEX	($61)	($62)	($6,452)	($6,646)	($7,736)	($917)																				($21,874)
OPEX																										
ANNUAL MAINTENANCE - ORIGINAL SCOPE ITEMS																										
LABOUR						($41)	($84)	($131)	($135)	($139)	($144)	($148)	($152)	($157)	($162)	($166)	($171)	($177)	($182)	($187)	($193)	($199)	($205)	($211)	($217)	($3,202)
OPERATING SUPPLIES						($1)	($1)	($2)	($2)	($2)	($2)	($2)	($2)	($2)	($3)	($3)	($3)	($3)	($3)	($3)	($3)	($3)	($3)	($3)	($3)	($51)
MAINTENANCE MATERIALS						($180)	($370)	($577)	($595)	($613)	($631)	($650)	($669)	($690)	($710)	($732)	($753)	($776)	($799)	($823)	($848)	($873)	($900)	($927)	($954)	($14,070)
SERVICES OR G&A						($0)	($1)	($2)	($2)	($2)	($2)	($2)	($2)	($2)	($2)	($2)	($2)	($2)	($2)	($2)	($2)	($2)	($2)	($2)	($3)	($38)
DUST SUPPRESSION WATER						($3)	($6)	($9)	($9)	($9)	($10)	($10)	($10)	($10)	($11)	($11)	($11)	($12)	($12)	($12)	($13)	($13)	($14)	($14)	($14)	($212)
POTABLE WATER						($0)	($0)	($0)	($0)	($0)	($0)	($0)	($0)	($0)	($0)	($0)	($0)	($0)	($0)	($0)	($0)	($0)	($0)	($0)	($0)	($2)
DIESEL FUEL						($249)	($514)	($802)	($826)	($850)	($876)	($902)	($929)	($957)	($986)	($1,016)	($1,046)	($1,077)	($1,110)	($1,143)	($1,177)	($1,213)	($1,249)	($1,286)	($1,325)	($19,533)
SUB TOTAL						($474)	($976)	($1,523)	($1,569)	($1,616)	($1,664)	($1,714)	($1,765)	($1,818)	($1,873)	($1,929)	($1,987)	($2,047)	($2,108)	($2,171)	($2,236)	($2,304)	($2,373)	($2,444)	($2,517)	($37,108)
ANNUAL MAINTENANCE - ADDITIONAL SCOPE ITEMS																										
NO ITEMS																										
SUB TOTAL																										
TOTAL OPEX						($474)	($976)	($1,523)	($1,569)	($1,616)	($1,664)	($1,714)	($1,765)	($1,818)	($1,873)	($1,929)	($1,987)	($2,047)	($2,108)	($2,171)	($2,236)	($2,304)	($2,373)	($2,444)	($2,517)	($37,108)
TOTAL COSTS (CAPEX + OPEX)	($61)	($62)	($6,452)	($6,646)	($7,736)	($1,391)	($976)	($1,523)	($1,569)	($1,616)	($1,664)	($1,714)	($1,765)	($1,818)	($1,873)	($1,929)	($1,987)	($2,047)	($2,108)	($2,171)	($2,236)	($2,304)	($2,373)	($2,444)	($2,517)	($58,982)
NET CASH FLOW	($61)	($62)	($6,452)	($6,646)	($7,736)	($147)	$1,562	$2,400	$2,433	$2,466	$2,499	$2,532	$2,566	$2,599	$2,633	$2,667	$2,701	$2,735	$2,769	$2,804	$2,838	$2,872	$2,907	$2,941	$6,477	$32,296
NET PRESENT VALUE (NPV)	$0																									
INTERNAL RATE OF RETURN (IRR)	8.2%																									

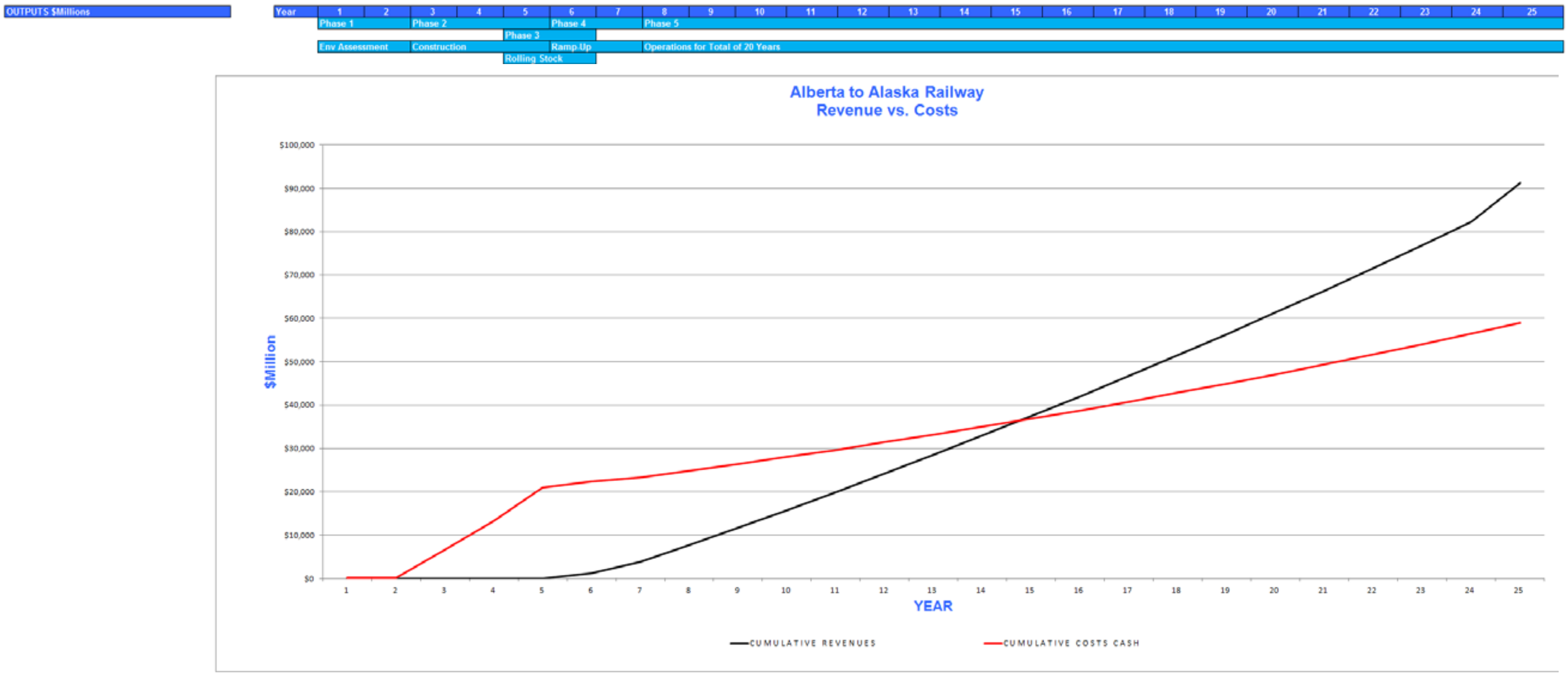


Figure 6 ShipperCo 1.0 mbpd Base Case DCF 20 Years

The Capex and Opex inputs for the ShipperCo 1.5 mbpd DCF analysis are shown in the following tables:

Table 17 ShipperCo 1.5 mbpd Capex Costs $2013 Millions CAD

DISCIPLINE	Low 5%	Expected	High 95%	ExpectedCost per Mile
ORIGINAL SCOPE ITEMS				
PART A: TRACK	$1,542	$1,982	$2,463	$1.31
PART B: EARTHWORKS	$5,118	$7,790	$10,662	$5.14
PART C: BRIDGES & STRUCTURES	$2,278	$2,975	$3,676	$1.96
PART D: TUNNELS	$226	$241	$254	$0.16
PART E: SIGNALS & COMMUNICATIONS	$285	$472	$681	$0.31
PART F: ROLLING STOCK & EQUIPMENT	$2,010	$2,307	$2,601	$1.52
PART G: FACILITIES	$641	$724	$812	$0.48
PART H: ENVIRONMENT	$166	$228	$294	$0.15
PART I: ENABLING WORKS	$182	$233	$277	$0.15
PART J: OTHERS	$2,920	$3,605	$4,359	$2.38
SUB TOTAL	**$15,367**	**$20,556**	**$26,078**	**$13.56**
ADDITIONAL SCOPE ITEMS				
NO ITEMS	$0	$0	$0	$0.00
	$0	$0	$0	$0.00
	$0	$0	$0	$0.00
	$0	$0	$0	$0.00
SUB TOTAL	**$0**	**$0**	**$0**	**$0.00**
GRAND TOTAL:	**$15,367**	**$20,556**	**$26,078**	**$13.56**
RANGE	**-25.25%**	**Expected**	**26.86%**	

Table 18 ShipperCo 1.5 mbpd Opex Costs in $2013 Millions CAD

DISCIPLINE	Low	Expected	High	Expected Cost per Mile
ORIGINAL SCOPE ITEMS				
LABOUR	$115	$128	$141	$0.08
OPERATING SUPPLIES	$2	$2	$2	$0.00
MAINTENANCE MATERIALS	$564	$627	$690	$0.41
SERVICES OR G&A	$1	$1	$1	$0.00
DUST SUPPRESSION WATER	$6	$7	$8	$0.00
POTABLE WATER	$0	$0	$0	$0.00
DIESEL FUEL	$830	$923	$1,015	$0.61
SUB TOTAL	**$1,519**	**$1,688**	**$1,857**	**$1.11**
ADDITIONAL SCOPE ITEMS				
NO ITEMS	$0	$0	$0	$0.00
	$0	$0	$0	$0.00
	$0	$0	$0	$0.00
	$0	$0	$0	$0.00
SUB TOTAL	**$0**	**$0**	**$0**	**$0.00**
GRAND TOTAL:	**$1,519**	**$1,688**	**$1,857**	**$1.11**
RANGE	-10.00%	**Expected**	10.00%	

The parameters and variables used in the ShipperCo 1.5 mbpd DCF Base Case for 20 years are shown in the following table:

Table 19 ShipperCo 1.5 mbpd Base Case 20 Year Parameters

			Year 6	Year 7	Year 8	Year 9	...
LIFE OF OPERATIONS IN YEARS	20						
OPERATIONS			33%	66%	100%	100%	
OPERATING DAYS PER YEAR	329						
BITUMIN BARRELS PER DAY (Millions)	2						
BITUMIN BARRELS PER YEAR (Millions)	494		163	326	494	494	494
BITUMEN TRAINS PER DAY	12						
BITUMEN TRAINS PER YEAR	3,948		1,303	2,606	3,948	3,948	3,948

DEBT/EQUITY STRUCTURE	
DEBT %	65%
EQUITY %	35%
TOTAL	**100%**
COST OF DEBT	6.0%
COST OF EQUITY	12.2%
WEIGHTED AVERAGE COST OF CAPITAL (DISCOUNT RATE)	**8.2%**
OPERATING RATIO	80%
REVENUE = COST PLUS	25%
OPERATING INCOME MARGIN (EBITA)	20%
$/BARREL RATE ESCALATION PER YEAR	2%
SCENARIO COSTS	Expected

CAPEX

ORIGINAL SCOPE ITEMS	$2013 Millions	Year 1	Year 2	Year 3	Year 4	Year 5	Year 6	Total	Escalation
PART A: TRACK	$1,982			$661	$661	$661	$0	$1,982	3.0%
PART B: EARTHWORKS	$7,790			$2,597	$2,597	$2,597	$0	$7,790	3.0%
PART C: BRIDGES & STRUCTURES	$2,975			$992	$992	$992	$0	$2,975	3.0%
PART D: TUNNELS	$241			$80	$80	$80	$0	$241	3.0%
PART E: SIGNALS & COMMUNICATIONS	$472			$157	$157	$157	$0	$472	3.0%
PART F: ROLLING STOCK & EQUIPMENT	$2,307			$0	$0	$1,154	$1,154	$2,307	3.0%
PART G: FACILITIES	$724			$241	$241	$241	$0	$724	3.0%
PART H: ENVIRONMENT	$228	$59	$59	$37	$37	$37	$0	$228	3.0%
PART I: ENABLING WORKS	$233			$78	$78	$78	$0	$233	3.0%
PART J: OTHERS	$3,605			$1,202	$1,202	$1,202	$0	$3,605	3.0%
SUB TOTAL	**$20,556**	**$59**	**$59**	**$6,044**	**$6,044**	**$7,197**	**$1,154**	**$20,556**	
ADDITIONAL SCOPE ITEMS									
NO ITEMS	$0	$0	$0	$0	$0	$0	$0	$0	3.0%
	$0	$0	$0	$0	$0	$0	$0	$0	3.0%
	$0	$0	$0	$0	$0	$0	$0	$0	3.0%
	$0	$0	$0	$0	$0	$0	$0	$0	3.0%
SUB TOTAL	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	
TOTAL	**$20,556**	**$59**	**$59**	**$6,044**	**$6,044**	**$7,197**	**$1,154**	**$20,556**	

OPEX

ANNUAL MAINTENANCE - ORIGINAL SCOPE ITEMS	$2013 Millions	Year 6	Year 7	Year 8	Year 9	...	Escalation
		33%	66%	100%	100%		
LABOUR	$128	$42	$85	$128	$128	$128	3.0%
OPERATING SUPPLIES	$2	$1	$1	$2	$2	$2	3.0%
MAINTENANCE MATERIALS	$627	$207	$414	$627	$627	$627	3.0%
SERVICES OR G&A	$1	$0	$1	$1	$1	$1	3.0%
DUST SUPPRESSION WATER	$7	$2	$5	$7	$7	$7	3.0%
POTABLE WATER	$0	$0	$0	$0	$0	$0	3.0%
DIESEL FUEL	$923	$304	$609	$923	$923	$923	3.0%
SUB TOTAL	**$1,688**	**$557**	**$1,114**	**$1,688**	**$1,688**	**$1,688**	
ANNUAL MAINTENANCE - ADDITIONAL SCOPE ITEMS							
NO ITEMS	$0	$0	$0	$0	$0	$0	3.0%
	$0	$0	$0	$0	$0	$0	3.0%
	$0	$0	$0	$0	$0	$0	3.0%
	$0	$0	$0	$0	$0	$0	3.0%
SUB TOTAL	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	
TOTAL	**$1,688**	**$557**	**$1,114**	**$1,688**	**$1,688**	**$1,688**	

SALVAGE VALUE

SALVAGE VALUE	$2013 Millions	ECONOMIC LIFE IN YEARS TOTAL	ECONOMIC LIFE IN YEARS AFTER SALVAGE	ANNUAL APPRECIATION
PART A: TRACK	$1,189	50	30	3.0%
PART E: SIGNALS & COMMUNICATIONS	$94	25	5	3.0%
PART F: ROLLING STOCK & EQUIPMENT	$461	25	5	3.0%
PART G: FACILITIES	$145	25	5	3.0%
TOTAL	**$1,890**	WEIGHTED ESCALATION		3.0%

The results for the ShipperCo 1.5 mbpd Base Case DCF are shown in the following table and figure:

Table 20 ShipperCo 1.5 mbpd Base Case DCF 20 Years

CALCULATIONS DCF $Millions

SCENARIO

LIFE OF OPERATIONS IN YEARS	20
COSTS	Expected
DISCOUNT RATE	8.2%
PROJECT OPERATING RATIO (OR)	77%
PROJECT OPERATING INCOME	23%
2013 PRICE $/BARREL	$8.14
ANNUAL $/BARREL ESCALATION	2%

Calculate OR For NPV = $0

Year	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24	25	TOTAL
	Phase 1		Phase 2		Phase 3	Phase 4		Phase 5																		
	Env Assessment		Construction		Rolling Stock	Ramp-Up		Operations for Total of 20 Years																		
OPERATIONS																										
BITUMIN BARRELS PER YEAR (Millions)						163	326	494	494	494	494	494	494	494	494	494	494	494	494	494	494	494	494	494	494	9,372
BITUMEN TRAINS PER YEAR						1,303	2,606	3,948	3,948	3,948	3,948	3,948	3,948	3,948	3,948	3,948	3,948	3,948	3,948	3,948	3,948	3,948	3,948	3,948	3,948	74,973
REVENUES PRICE $/BARREL	$8.30	$8.47	$8.64	$8.81	$8.99	$9.17	$9.35	$9.54	$9.73	$9.92	$10.12	$10.33	$10.53	$10.74	$10.96	$11.18	$11.40	$11.63	$11.86	$12.10	$12.34	$12.59	$12.84	$13.09	$13.36	
REVENUE						$1,493	$3,046	$4,707	$4,802	$4,898	$4,996	$5,095	$5,197	$5,301	$5,407	$5,515	$5,626	$5,738	$5,853	$5,970	$6,090	$6,211	$6,336	$6,462	$6,592	$105,335
SALAVAGE VALUE																									$3,957	$3,957
TOTAL REVENUES						**$1,493**	**$3,046**	**$4,707**	**$4,802**	**$4,898**	**$4,996**	**$5,095**	**$5,197**	**$5,301**	**$5,407**	**$5,515**	**$5,626**	**$5,738**	**$5,853**	**$5,970**	**$6,090**	**$6,211**	**$6,336**	**$6,462**	**$10,548**	**$109,292**
COSTS																										
CAPEX																										
ORIGINAL SCOPE ITEMS																										
PART A: TRACK			($722)	($744)	($766)																					($2,231)
PART B: EARTHWORKS			($2,838)	($2,923)	($3,010)																					($8,771)
PART C: BRIDGES & STRUCTURES			($1,084)	($1,116)	($1,149)																					($3,349)
PART D: TUNNELS			($88)	($90)	($93)																					($271)
PART E: SIGNALS & COMMUNICATIONS			($172)	($177)	($182)																					($531)
PART F: ROLLING STOCK & EQUIPMENT					($1,337)	($1,377)																				($2,715)
PART G: FACILITIES			($264)	($272)	($280)																					($816)
PART H: ENVIRONMENT	($61)	($62)	($40)	($41)	($42)																					($247)
PART I: ENABLING WORKS			($85)	($87)	($90)																					($262)
PART J: OTHERS			($1,313)	($1,353)	($1,393)																					($4,059)
SUB TOTAL	($61)	($62)	($6,604)	($6,802)	($8,344)	($1,377)																				($23,251)
ADDITIONAL SCOPE ITEMS																										
NO ITEMS																										
SUB TOTAL																										
TOTAL CAPEX	($61)	($62)	($6,604)	($6,802)	($8,344)	($1,377)																				($23,251)
OPEX																										
ANNUAL MAINTENANCE - ORIGINAL SCOPE ITEMS																										
LABOUR						($50)	($104)	($162)	($167)	($172)	($177)	($183)	($188)	($194)	($200)	($206)	($212)	($218)	($225)	($231)	($238)	($245)	($253)	($260)	($268)	($3,953)
OPERATING SUPPLIES						($1)	($1)	($2)	($2)	($2)	($2)	($2)	($3)	($3)	($3)	($3)	($3)	($3)	($3)	($3)	($3)	($3)	($3)	($3)	($4)	($53)
MAINTENANCE MATERIALS						($247)	($509)	($794)	($818)	($843)	($868)	($894)	($921)	($949)	($977)	($1,006)	($1,037)	($1,068)	($1,100)	($1,133)	($1,167)	($1,202)	($1,238)	($1,275)	($1,313)	($19,358)
SERVICES OR G&A						($0)	($1)	($2)	($2)	($2)	($2)	($2)	($2)	($2)	($2)	($2)	($2)	($2)	($2)	($2)	($2)	($2)	($2)	($2)	($3)	($38)
DUST SUPPRESSION WATER						($3)	($6)	($9)	($9)	($9)	($10)	($10)	($10)	($10)	($11)	($11)	($11)	($12)	($12)	($12)	($13)	($13)	($14)	($14)	($14)	($212)
POTABLE WATER						($0)	($0)	($0)	($0)	($0)	($0)	($0)	($0)	($0)	($0)	($0)	($0)	($0)	($0)	($0)	($0)	($0)	($0)	($0)	($0)	($2)
DIESEL FUEL						($364)	($749)	($1,169)	($1,204)	($1,240)	($1,277)	($1,316)	($1,355)	($1,396)	($1,438)	($1,481)	($1,525)	($1,571)	($1,618)	($1,666)	($1,716)	($1,768)	($1,821)	($1,876)	($1,932)	($28,480)
SUB TOTAL						($665)	($1,370)	($2,138)	($2,202)	($2,268)	($2,336)	($2,406)	($2,479)	($2,553)	($2,629)	($2,708)	($2,790)	($2,873)	($2,960)	($3,048)	($3,140)	($3,234)	($3,331)	($3,431)	($3,534)	($52,095)
ANNUAL MAINTENANCE - ADDITIONAL SCOPE ITEMS																										
NO ITEMS																										
SUB TOTAL																										
TOTAL OPEX						($665)	($1,370)	($2,138)	($2,202)	($2,268)	($2,336)	($2,406)	($2,479)	($2,553)	($2,629)	($2,708)	($2,790)	($2,873)	($2,960)	($3,048)	($3,140)	($3,234)	($3,331)	($3,431)	($3,534)	($52,095)
TOTAL COSTS (CAPEX + OPEX)	**($61)**	**($62)**	**($6,604)**	**($6,802)**	**($8,344)**	**($2,042)**	**($1,370)**	**($2,138)**	**($2,202)**	**($2,268)**	**($2,336)**	**($2,406)**	**($2,479)**	**($2,553)**	**($2,629)**	**($2,708)**	**($2,790)**	**($2,873)**	**($2,960)**	**($3,048)**	**($3,140)**	**($3,234)**	**($3,331)**	**($3,431)**	**($3,534)**	**($75,346)**
NET CASH FLOW	**($61)**	**($62)**	**($6,604)**	**($6,802)**	**($8,344)**	**($549)**	**$1,676**	**$2,569**	**$2,599**	**$2,629**	**$2,659**	**$2,689**	**$2,719**	**$2,748**	**$2,778**	**$2,807**	**$2,836**	**$2,865**	**$2,894**	**$2,922**	**$2,950**	**$2,977**	**$3,005**	**$3,031**	**$7,015**	**$33,946**
NET PRESENT VALUE (NPV)	**($0)**																									
INTERNAL RATE OF RETURN (IRR)	**8.2%**																									

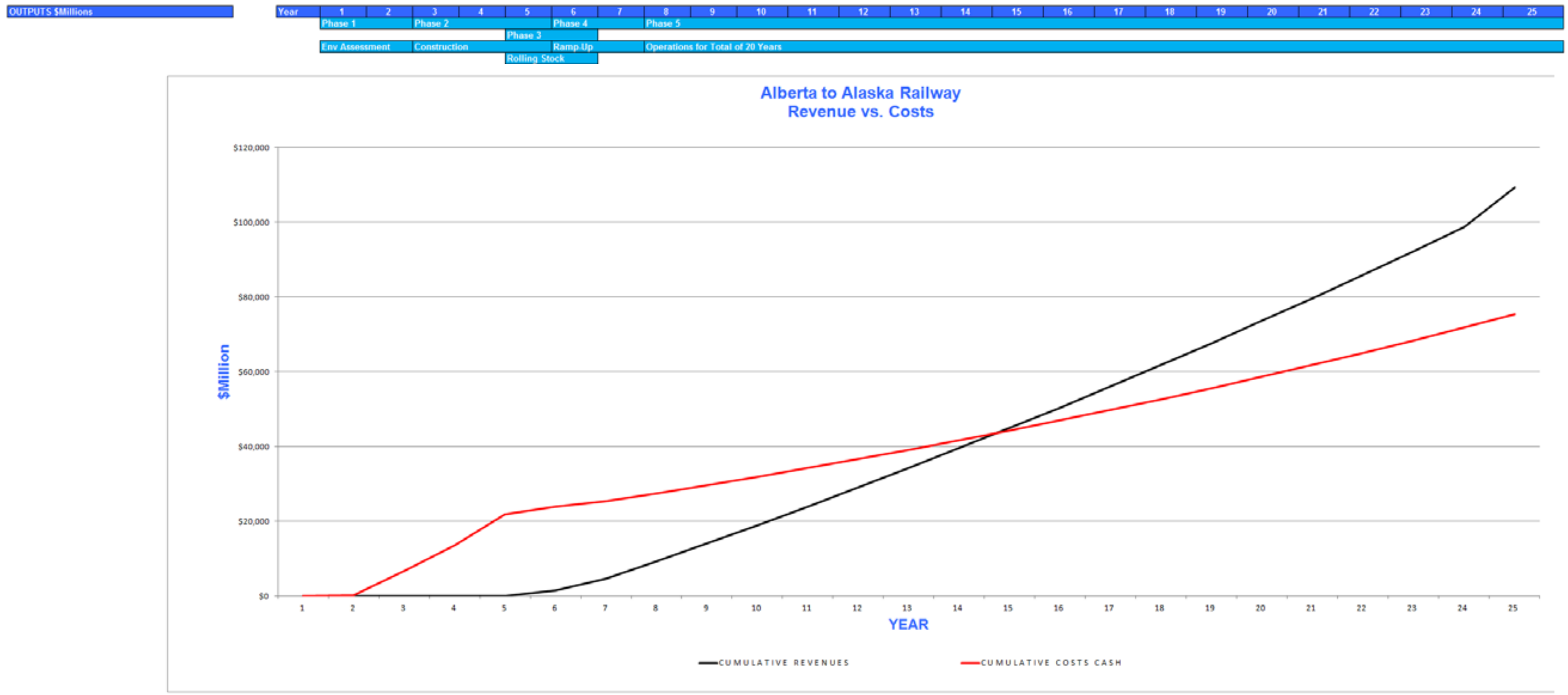


Figure 7 ShipperCo 1.5 mbpd Base Case DCF 20 Years

1.4.2 DCF Sensitivity Analysis

The sensitivity analysis for the ShipperCo option has been broken down into three general areas of review. The first analysis looks at general parameters such as changes in Capex and Opex and discusses their effect on the model. The second area of analysis is a review of the impact of the cost of debt at various levels on the overall project. Finally the third section is an analysis of operations beyond the base case of 20 years. The DCF Sensitivity Analysis was applied to the railway from Alberta to Delta Junction.

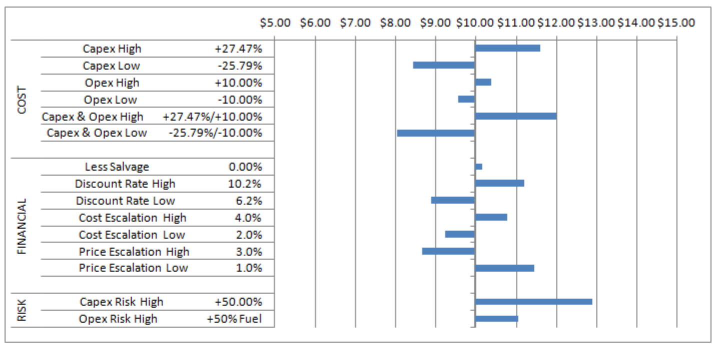
1.4.2.1 General Parameters

The results of the General Parameter Sensitivity Analysis for the ShipperCo scenarios are summarised in the following table:

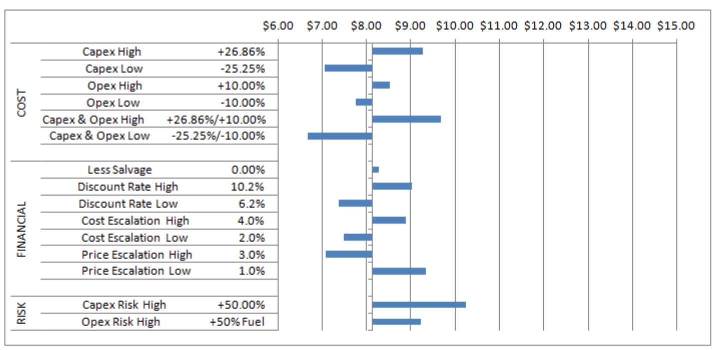
Table 21 ShipperCo Sensitivity Analysis

DESCRIPTION		CHANGES TO BASE CASE	$/BARREL 2013
1 mbpd SCENARIOS			
20 YEAR OPERATION			
BASE CASE	Expected	NA	$9.96
COST	Capex High	+27.47%	$11.59
	Capex Low	-25.79%	$8.44
	Opex High	+10.00%	$10.38
	Opex Low	-10.00%	$9.55
	Capex & Opex High	+27.47%/+10.00%	$12.00
	Capex & Opex Low	-25.79%/-10.00%	$8.03
FINANCIAL	Less Salvage	0.00%	$10.15
	Discount Rate High	10.2%	$11.20
	Discount Rate Low	6.2%	$8.89
	Cost Escalation High	4.0%	$10.78
	Cost Escalation Low	2.0%	$9.23
	Price Escalation High	3.0%	$8.66
	Price Escalation Low	1.0%	$11.45
RISK	Capex Risk High	+50.00%	$12.89
	Opex Risk High	+50% Fuel	$11.05
1.5 mbpd SCENARIOS			
20 YEAR OPERATION			
BASE CASE	Expected	NA	$8.14
COST	Capex High	+26.86%	$9.28
	Capex Low	-25.25%	$7.07
	Opex High	+10.00%	$8.53
	Opex Low	-10.00%	$7.75
	Capex & Opex High	+26.86%/+10.00%	$9.68
	Capex & Opex Low	-25.25%/-10.00%	$6.67
FINANCIAL	Less Salvage	0.00%	$8.29
	Discount Rate High	10.2%	$9.02
	Discount Rate Low	6.2%	$7.38
	Cost Escalation High	4.0%	$8.88
	Cost Escalation Low	2.0%	$7.49
	Price Escalation High	3.0%	$7.08
	Price Escalation Low	1.0%	$9.35
RISK	Capex Risk High	+50.00%	$10.24
	Opex Risk High	+50% Fuel	$9.22

$/BARREL RELATIVE TO BASE CASE (1 mbpd)



$/BARREL RELATIVE TO BASE CASE (1.5 mbpd)



In each of the scenarios above the project payback occurs in about year 15 or after about 10 years of operation.

1.4.2.2 Cost of Debt

In the event that the Railway secures a loan or loan guarantee from a Canadian or foreign sovereign, the cost of debt for the overall project (i.e. for ShipperCo) may be as low as 3.5% for long-term debt based on the latest market pricing data. The rationale for this cost of debt, which can be characterized as a reasonable best-case scenario for sovereign participation in the debt financing of the Alberta to Alaska Railway, is described below. Under this scenario, the ShipperCo transportation cost could be as low as $7.50/bbl (1.5 mbpd case) or $9.07/bbl (1 mbpd case) as shown in the Figure below, assuming the same debt equity structure (65:35) and the same cost of equity. A sovereign guarantee could potentially support a somewhat higher debt-equity ratio (e.g. 75:25).[14] and would also entail a lower cost of equity, but this has not been factored into this analysis.

This 3.5% cost of debt is based on the assumption that the debt issued by RailCo would be explicitly guaranteed by the Government of Canada (GoC), as in the case of the debt for the Lower Churchill hydroelectric power generation and transmission projects which is expected to be issued by Nalcor Energy and Emera (the Newfoundland and Nova Scotia power companies) and guaranteed by the Government of Canada up to a limit of $6.3. Billion.[15] The latest GoC bond yields for debt maturing in 20 years are just under 3.2%.[16] GoC-backed bonds issued by the Alberta to Alaska Railway would trade at a slightly higher yield to GoC bonds, just as Canada Mortgage Bonds (CMBs), which are fully backed by the GoC, tend to trade at a slight premium to equivalent-term GoC bonds. The CMB spread for 5-year bonds has historically been less than 20 basis points.[17] Allowing for up to almost double the CMB 5-yr spread for a 20-year, this would give a debt cost of 3.5% based on current bond market yields.
In the event that the Alberta to Alaska Railway secured participation of a sovereign-type lender other than the Government of Canada, the debt cost would be either equal to or higher that 3.5% in practically all cases. For example, a provincial sovereign within Canada would almost certainly carry a bond yield equal to or higher than the 3.2% GoC yield for an equivalent term. The value of a debt guarantee provided by a non-Canadian sovereign would depend on the credit quality and rating of the sovereign in question. One of the highest quality counterparties worldwide is the US Government. US 30-year government bonds are currently trading at 3.9% yield and 10-year bonds at 2.84% (Bloomberg 4 December 2013), which are considerably higher than equivalent GoC yields. Therefore, it is unlikely that the participation of a non-Canadian sovereign in the financing of the Alberta to Alaska Railway would yield a cost of debt significantly below 3.5%, assuming commercial terms prevail.

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[14] *Note that the term sheet covering the federal loan guarantee between the Government of Canada and Nalcor, Emera, the Province of Newfoundland and the Province of Nova Scotia required a minimum equity ratio of 35% for the Muskrat Falls hydro generation facility and for the transmission project between Muskrat Falls and Churchill Falls (i.e. a debt-equity ratio of 65:35) and a 25% minimum equity stake for the transmission project connecting the Island of Newfoundland to the generation facilities in Labrador. See para. 3.1 of term sheet: http://www.nrcan.gc.ca/sites/www.nrcan.gc.ca/files/files/2012-11-29-TL-Churchill-Projects-eng.pdf.*

[15] *See the term sheet agreed between the GoC and Nalcor, Emera, the Province of Newfoundland and the Province of Nova Scotia: http://www.nrcan.gc.ca/sites/www.nrcan.gc.ca/files/files/2012-11-29-TL-Churchill-Projects-eng.pdf*

[16] For example, the GoC bond (with a 5.75% coupon) maturing in 01.6.2033 is trading at a bid yield of 3.18% (4 December 2013).

[17] *See the Bank of Canada report "Improving the Resilience of Core Funding Markets" (p.42) accessed at http://www.bankofcanada.ca/wp-content/uploads/2012/01/fsr-1209-fontaine.pdf.*

1.5 Key Data and Assumptions

ShipperCo Base Case for 20 Year Operation

<u>Debt/Equity Structure</u>

- Debt 65%
- Equity 35%

<u>Cost of Capital</u>

- Debt 6.0%
- Equity 12.2%
- WACC 8.2%

<u>Base Case Sensitivities for Cost of Capitals</u>

- 1.0 mbpd $9.96/barrel
- 1.5 mbpd $8.14/barrel

Cost of capital for debt was adjusted from 6.0% to 3.5%, 4.0%, 4.5%, 5.0% and 5.5% for 1.0 mbpd and 1.5 mbpd and the respective changes to ShipperCo's $/barrel cost in 2013 dollars are shown in the following figure:

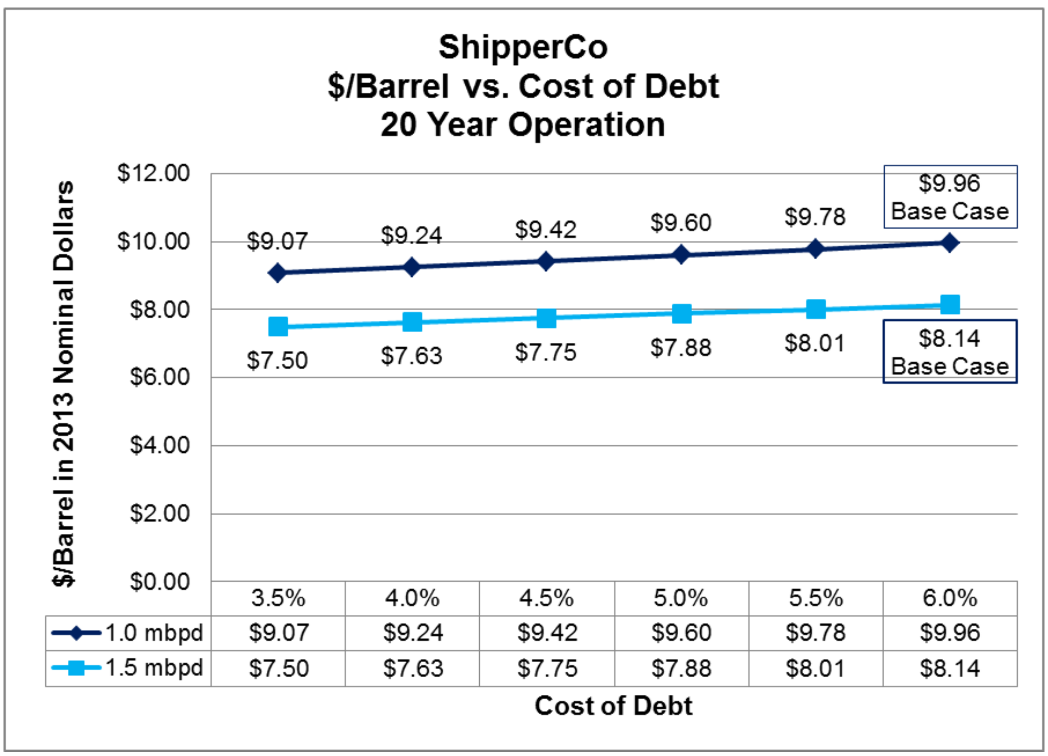


Figure 8 ShipperCo: Effect of Cost of Debt

1.5.1 Assessment of DCF

The operations model of the Alberta to Alaska Railway is designed and built to haul bitumen without the need for diluent. As such, the railway can handle more bitumen per unit volume than other transportation methods that require a blend of bitumen and diluents. Thus, the ShipperCo pricing model should be adjusted to compare the equivalent cost per barrel of 100% bitumen versus a bitumen/diluents mix (dilbit). The ShipperCo Sensitivity Analysis yields a range of scenarios with estimates for all in costs to the shipper for the haulage of bitumen from the loading facility in Alberta to the unloading facility in Alaska.

Table 22 shows the equivalent cost per barrel of various mixes of bitumen and diluents. For example, in the 1.5 mbpd 20 year scenario, it is expected to cost ShipperCo $8.14 to ship a barrel of 100% bitumen by the Alberta to Alaska Railway. The equivalent cost of an alternative means of transportation in which bitumen needs be mixed with 30% diluents in order to be transported is $5.70 per barrel. The $5.70 per barrel cost of the alternative means must cover the cost and recovery of the diluents as well as the transportation costs of only 70% bitumen per barrel. Therefore with a mix of 70% bitumen and 30% diluents, an alternative to the Alberta to Alaska Railway would have to transport about 1.43 barrels of this mix at $5.70/barrel (i.e., 1.43 barrels x $5.70/barrel) to be equivalent to 1.0 barrel transported by the Alberta to Alaska Railway at $8.14/barrel containing 100% bitumen.

Table 22 ShipperCo Base Case Estimates and Equivalents at Various % Levels of Bitumen

	ShipperCo			
Scenario 20 Year Duration mbpd	1.0			
% Diluent/Barrel	0%	10%	20%	30%
% Bitumen/Barrel	100%	90%	80%	70%
$/Barrel Equivalent Cost	$9.96	$8.96	$7.97	$6.97
Scenario 20 Year Duration mbpd	1.5			
% Diluent/Barrel	0%	10%	20%	30%
% Bitumen/Barrel	100%	90%	80%	70%
$/Barrel Equivalent Cost	$8.14	$7.33	$6.51	$5.70

These estimates are shown graphically in the following figures:

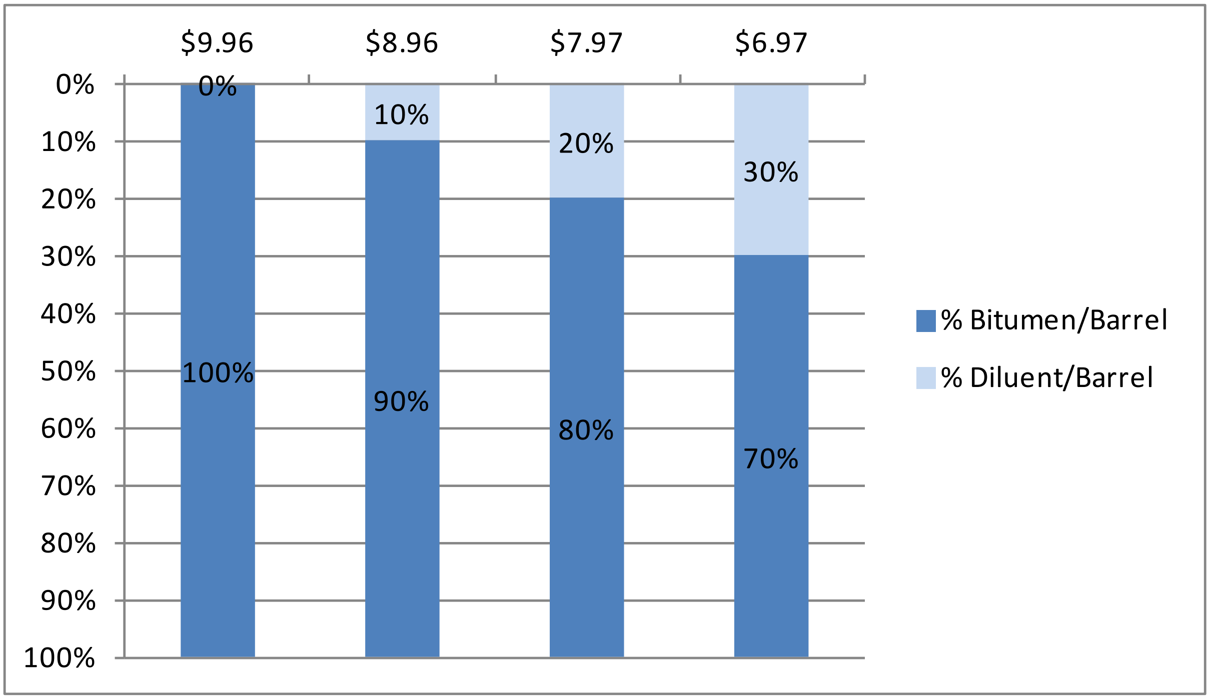


Figure 9 ShipperCo Base Case Estimate 1.0 mbpd 20 Years and Equivalents at Various % Levels of Bitumen

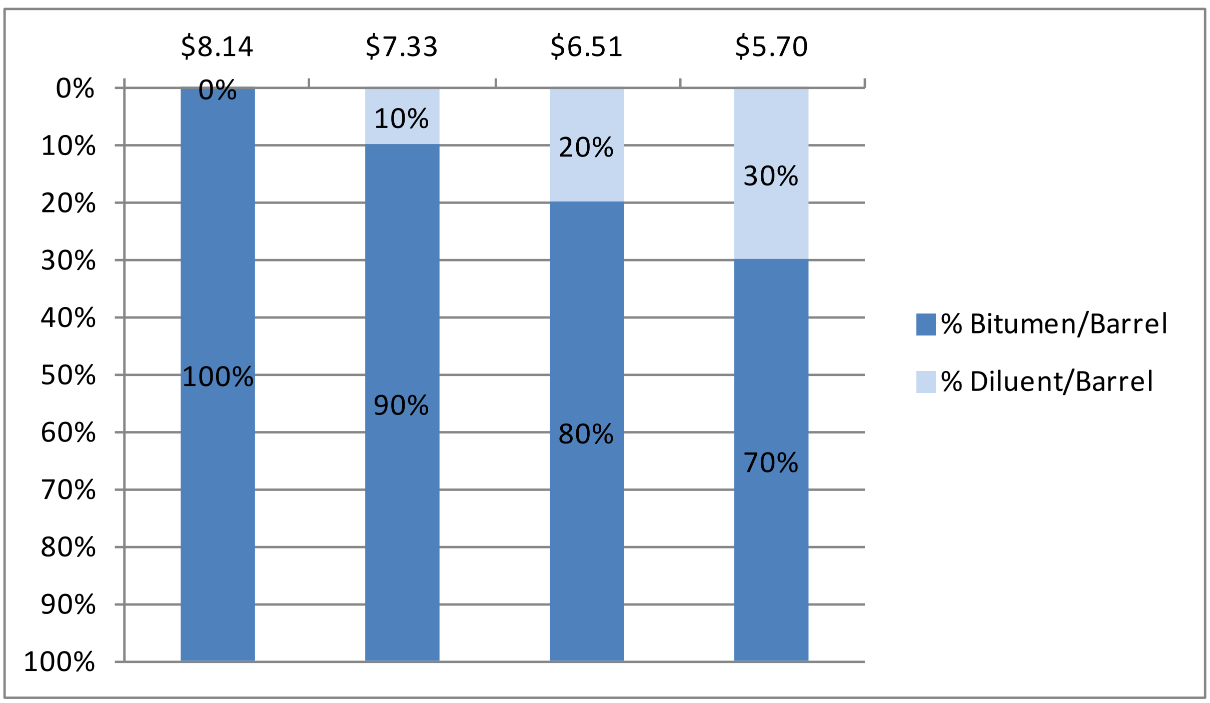


Figure 10 ShipperCo Base Case Estimate 1.5 mbpd 20 Years and Equivalents at Various % Levels of Bitumen

1.6 RailCo Financial Analysis

1.6.1 DCF Analysis

The RailCo case is the same as the ShipperCo case with the exception of rail tank cars. In addition to the per barrel toll charged by RailCo, ShipperCo bears the Capex and Opex costs for the tank cars. Consequently the DCF analysis for RailCo must exclude these costs. The rail tank car costs that are excluded in the RailCo case are:

- Capex
  - Capital cost of rail tank cars
  - Capital cost of maintenance facilities for rail tank cars
- Opex
  - Operational costs for the maintenance of rail tank cars

These costs were removed for both the 1.0 mbpd and 1.5 mbpd scenarios and were adjusted as shown in the following table:

Table 23 RailCo Capex and Opex Costs

$Million	ShipperCo A	Tank Cars B	RailCo =A-B
1.0 mbpd			
Capex	19,368	1,126	18,242
Opex	1,202	48	1,154
1.5 mbpd			
Capex	20,556	1,699	18,858
Opex	1,688	70	1,618

The costs for the RailCo case were then treated in the DCF analysis in the same manner as the ShipperCo case and with the same parameters (see Table 15 and Table 19). This analysis yielded very similar outputs to the ShipperCo case (see Tables 21, 22, 26 and 27). The results of the RailCo DCF analysis show that depending on the scenario the rail tank cars represent a cost to ShipperCo ranging from about $0.41/barrel to $0.64/barrel.

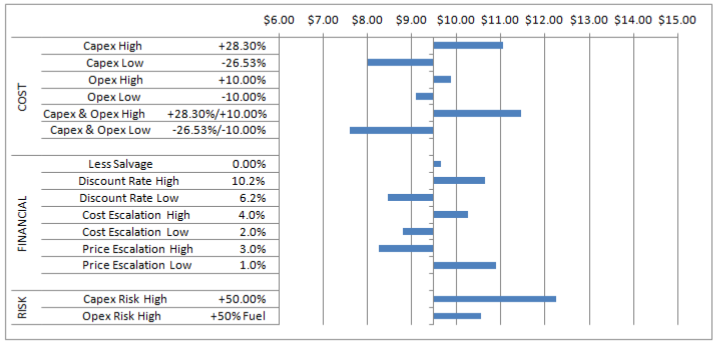
1.6.2 DCF Sensitivity Analysis

The results of the Sensitivity Analysis for the RailCo scenarios are summarised in the following table:

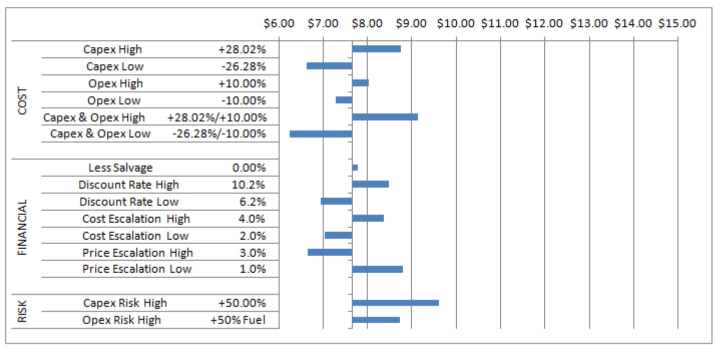
Table 24 RailCo Sensitivity Analysis

DESCRIPTION		CHANGES TO BASE CASE	$/BARREL 2013
1 mbpd SCENARIOS			
20 YEAR OPERATION			
BASE CASE	Expected	NA	$9.49
COST	Capex High	+28.30%	$11.06
	Capex Low	-26.53%	$8.01
	Opex High	+10.00%	$9.88
	Opex Low	-10.00%	$9.09
	Capex & Opex High	+28.30%/+10.00%	$11.46
	Capex & Opex Low	-26.53%/-10.00%	$7.61
FINANCIAL	Less Salvage	0.00%	$9.65
	Discount Rate High	10.2%	$10.66
	Discount Rate Low	6.2%	$8.47
	Cost Escalation High	4.0%	$10.27
	Cost Escalation Low	2.0%	$8.79
	Price Escalation High	3.0%	$8.25
	Price Escalation Low	1.0%	$10.90
RISK	Capex Risk High	+50.00%	$12.26
	Opex Risk High	+50% Fuel	$10.57
1.5 mbpd SCENARIOS			
20 YEAR OPERATION			
BASE CASE	Expected	NA	$7.66
COST	Capex High	+28.02%	$8.76
	Capex Low	-26.28%	$6.63
	Opex High	+10.00%	$8.04
	Opex Low	-10.00%	$7.28
	Capex & Opex High	+28.02%/+10.00%	$9.13
	Capex & Opex Low	-26.28%/-10.00%	$6.25
FINANCIAL	Less Salvage	0.00%	$7.78
	Discount Rate High	10.2%	$8.48
	Discount Rate Low	6.2%	$6.95
	Cost Escalation High	4.0%	$8.36
	Cost Escalation Low	2.0%	$7.04
	Price Escalation High	3.0%	$6.66
	Price Escalation Low	1.0%	$8.80
RISK	Capex Risk High	+50.00%	$9.60
	Opex Risk High	+50% Fuel	$8.73

$/BARREL RELATIVE TO BASE CASE



$/BARREL RELATIVE TO BASE CASE



In each of the scenarios above the project payback occurs in about year 15 or after about 10 years of operation.

1.6.3 Assessment of DCF

As stated earlier, the operations model of the Alberta to Alaska Railway is designed and built to haul bitumen without diluent. The RailCo Sensitivity Analysis yields a range of scenarios with estimates for an all in toll it would charge the shipper for the haulage of bitumen from the loading facility in Alberta to the unloading facility in Alaska. The table below shows the various Base Case estimates of the tolls and their equivalent for the movement of bitumen at various levels of diluent.

Table 25 shows the equivalent cost per barrel of various mixes of bitumen and diluents. For example, in the 1.5 mbpd 20 year scenario, it is expected to cost RailCo $7.66 to ship a barrel of 100% bitumen by the Alberta to Alaska Railway. The equivalent cost of an alternative means of transportation in which bitumen needs be mixed with 30% diluents in order to be transported is $5.36 per barrel. The $5.36 per barrel cost of the alternative means must cover the cost and recovery of the diluents as well as the transportation costs of 70% bitumen per barrel. Therefore with a mix of 70% bitumen and 30% diluents, an alternative to the Alberta to Alaska Railway would have to transport about 1.43 barrels of this mix at $5.36/barrel (i.e., 1.43 barrels x $5.36/barrel) to be equivalent to 1.0 barrel transported by the Alberta to Alaska Railway at $7.66/barrel containing 100% bitumen.

Table 25 RailCo Base Case Estimates and Equivalents at Various % Levels of Bitumen

	RailCo			
Scenario 20 Year Duration mbpd	1.0			
% Diluent/Barrel	0%	10%	20%	30%
% Bitumen/Barrel	100%	90%	80%	70%
$/Barrel Equivalent Cost	$9.49	$8.54	$7.59	$6.64
Scenario 20 Year Duration mbpd	1.5			
% Diluent/Barrel	0%	10%	20%	30%
% Bitumen/Barrel	100%	90%	80%	70%
$/Barrel Equivalent Cost	$7.66	$6.89	$6.13	$5.36

These estimates are shown graphically in the following figures:

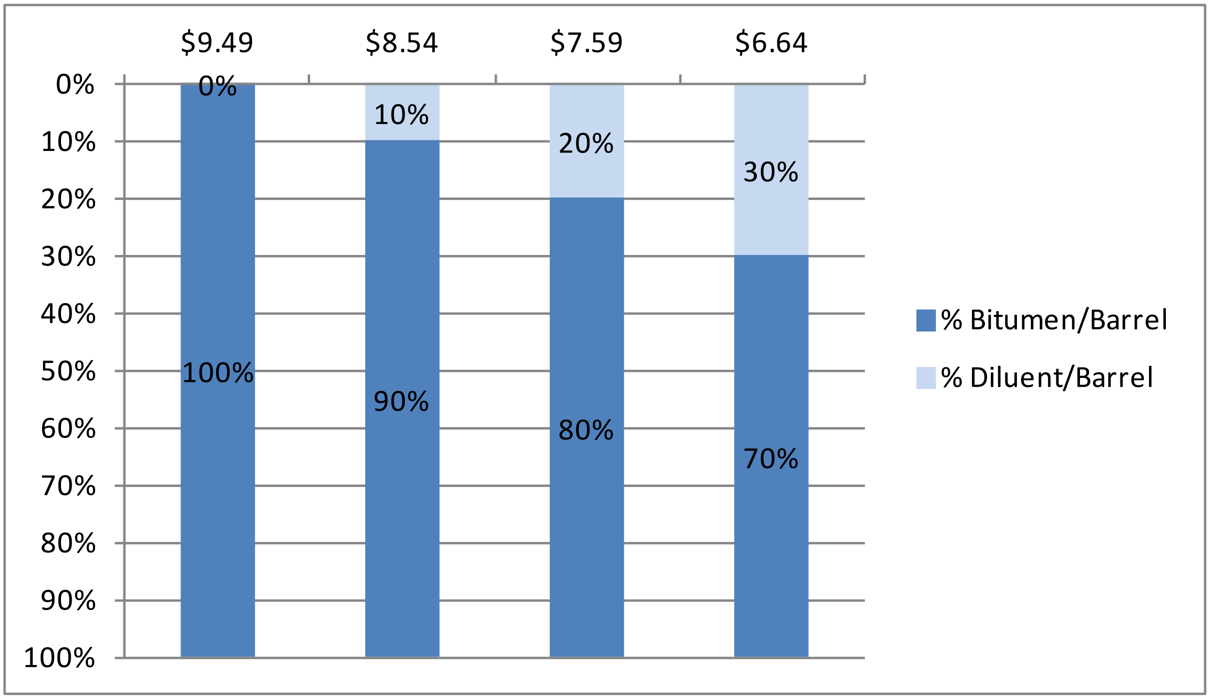


Figure 11 RailCo Base Case Estimate 1.0 mbpd 20 Years and Equivalents at Various % Levels of Bitumen

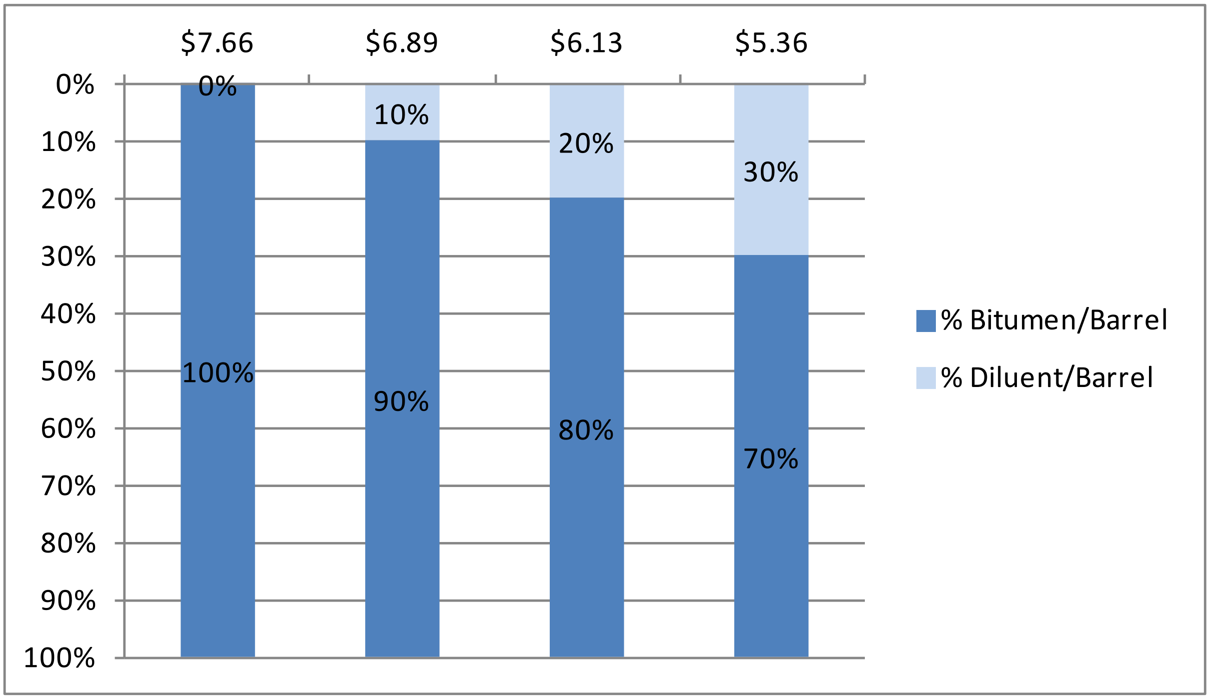


Figure 12 RailCo Base Case Estimate 1.5 mbpd 20 Years and Equivalents at Various % Levels of Bitumen

1.6.4 Capital Funding Requirements

The total capital funding requirements for the Alberta to Alaska railroad are shown in Table 13, Table 17, and Table 23. The capital spending requirements are shown on a per year basis in Table 16 and Table 20. The estimates for capital spending were obtained from the pre-feasibility engineering study. The total capital funding requirements range from $14.4 to $24.7 billion in the 1.0 mbpd case, with an expected value of $19.4 billion. The total capital funding requirements range from $15.4 to $26.1 billion in the 1.5 mbpd case, with an expected value of $20.6 billion.

1.6.5 Other Revenue Opportunities

There are significant opportunities to generate additional revenue along this proposed rail line. The most significant opportunities focus around two key areas: the ability to back haul from Alaska to Alberta and the ability to move other commodities by rail. This study assumes that the rail cars are returning empty from Alaska back to Alberta. Other potential commodities could include grains, coal, lumber, ore, and potash, to name a few.

Other revenue generating opportunities include:

- The proposed route has at least four interconnections with other existing railroads
- The proposed route has several rail spurs that could be developed
- The proposed route passes through large portions of undeveloped areas.

1.6.6 Tidewater Options

An additional sensitivity analysis was conducted to assess the financial impact of different routes and methods to move the bitumen to tidewater at the Port of Valdez in Alaska.

The chosen route for this study terminates at Delta Junction, where it is expected that the bitumen will be transferred to the TAPS pipeline for transit to Valdez. This is preferred because from Delta Junction, the Alberta to Alaska Railway will be able to connect to the Alaska Railroad, once the Alaska Railroad extension is complete.

Other alternatives could be studied to move the bitumen from an alternate terminal location and directly to the Port of Valdez. Such alternatives include the following:

- possibly negotiating the transfer of bitumen to the TAPS if this is agreeable to its owners,
- building a new alternate pipeline parallel to TAPS a new marine terminal from Delta Junction to Valdez, or
- building a new alternate rail alignment from Tok to Glennallen, to move the rail terminal closer to a new pipeline to and new marine terminal at Valdez

The alternate rail alignment from Tok to Glennallen was investigated in this sensitivity analysis, to determine at a high level if this alternative would significantly impact the business case. This alignment option moves the terminating station closer to Valdez, at Glennallen, but due to the coastal mountain range, it is not economically feasible to get all the way to Valdez by rail. Therefore at Glennallen, as with Delta Junction, a connection to the TAPS pipeline is required or an alternate pipeline must be constructed.

The construction and operating costs were estimated to determine the impact on the price per barrel toll charge of bitumen haul to extend the railway an additional 50 km to Glennallen, as opposed to Delta Junction, and build a dedicated pipeline from Glennallen to Valdez, approximately 195 km. This pipeline cost was estimated to be $1.0 Billion. The rail segment from Tok to Glennallen was not studied using the same methodology as the main Alberta to Alaska rail study. Rather a high level review of the terrain was conducted and values were applied for construction and operations that were derived from other locations along the alignment that appeared to have similar looking terrain.

The Tok to Glennallen alignment is expected to be considerably more expensive to build than the Tok to Delta Junction alignment, due to the rugged terrain and requirement for high bridges. In addition, this route does go through sections of Wrangell-St. Elias National Park & Preserve, and to avoid some conflicts three tunnels are likely required. This required additional capital of $1.1 Billion for the alternate route. The result of this analysis was that the additional capital cost of the Tok to Glennallen rail alternative, plus the pipeline to Valdez totaled approximately $2.1 Billion

Although not studied in any detail, from a high level estimate perspective, should it be required the construction of a new marine facility and port in the Valdez area was assumed to be approximately $6.7 billion dollars depending on the land requirements and the type of facilities required with an estimated $30 million per year in operating cost. The high level estimate for constructing a new pipeline from Delta Junction to Valdez, a distance of 430 km, was roughly calculated at $2.2 Billion.

1.7 Risk Assessment

A quantitative risk assessment using the DCF model was performed to evaluate some of the high level risks associated with the project. The risk assessment was used to guide design and development strategies during the preliminary feasibility study. The following risks have undergone high level quantitative assessment:

- Schedule risk
- Capex budget risk
- Opex budget risk.

The final risk discussed in this section deals with market risk. Market risk is examined using a high level qualitative assessment.

1.7.1 Schedule Risk

Using the DCF model risks related to scheduling of the project were examined. It was determined that the highest risks to schedule would occur during the early stages of the project, specifically during the environmental assessment and construction phases of the project. Schedule risk has implications for the overall budget, the possibility of a lower return for the RailCo, and a risk of missing a window of market opportunity. Two different scenarios were modelled to examine the impact of:

- Extending the environmental assessment phase of the project by 50%, from two years to three years
- Extending the construction phase of the project by 33%, from three years to four years.

Using the 1.0 mbpd for 20 years as the base case and extending the environmental assessment phase of the project by 50%, the total cost per barrel increased 0.8%. By extending the construction phase of the project by 33%, the total cost per barrel increased by 4.3%.

1.7.2 Capex Budget Risk

The capital expenditure budget risk is the risk associated with higher capital spending than planned. In order to quantify this risk, the DCF model examined a low, expected, and high value for capital spending. The estimates for capital spending were obtained from the pre-feasibility engineering study. The capital expenditure budget was increased by 50% and Table 21 and Table 24 show the sensitivity analysis for the ShipperCo and RailCo scenarios.

The increased capital expenditure budget has the biggest overall impact on the cost of shipping a barrel in all the scenarios. When capital expenditure is increased by 50%, the cost per barrel can increase by 26% to 29%, depending on the scenario.

1.7.3 Opex Budget Risk

The operating expenditure budget risk is the risk associated with higher than planned operating expenses. In order to quantify this risk, the DCF model examined a low, expected, and high value for operating spending. The estimates for operational spending were obtained from the pre-feasibility engineering study. To simulate operating expenditure budget risk, the largest single operating expense (i.e., diesel fuel) was increased by 50% and Table 21 and Table 24 show the sensitivity analysis for the ShipperCo and RailCo scenarios. The increased operating expenditure budget can increase the cost per barrel by 11% to 13%, depending on the scenario.

1.7.4 Market Risk

The market risks are a category of risks that are beyond the control of the ShipperCo or the RailCo. As such, these risks are much more difficult to evaluate on a quantitative level and must be examined on a qualitative level. High level market risks include:

- Supply and demand of bitumen
- Alternatives for moving bitumen
- Proposed pipelines and timing of new developments
- Alternative markets.

Both supply and demand of bitumen are expected to increase over the medium term. However, these increases are not consistent across the globe, with some areas expecting much higher increases than others. These discrepancies in supply and demand will result in opportunities for producers and shippers alike, assuming they can get the bitumen to market. The Alberta to Alaska railroad will provide a steady supply of bitumen to these growing markets, but the railroad will be exposed to supply and demand fluctuations in the price of bitumen without guaranteed “take-or-pay” contracts.

There are few alternatives to moving bitumen in large quantities. The single largest alternative is a pipeline. While there are several bitumen pipelines planned, there is enough uncertainty in the timing and environmental constraints at the planning stage to warrant further investigation of an alternative to a pipeline, namely, a purpose built railroad. The Alberta to Alaska railroad will be exposed to market risks associated with pipeline developments and the timing of these proposed pipeline developments.

Currently, the majority of bitumen produced in Canada is transported to the United States.

The Asian market is looking for security and diversity of the supply of Canadian petroleum products. The Alberta to Alaska railroad will provide a steady supply of bitumen to these alternative markets, but the railroad will be exposed to global price competition for these markets without guaranteed “take-or-pay” contracts.

An additional sensitivity analysis was conducted to assess the financial impact of extending the durations of the Environmental Assessment and Construction periods beyond what was previously defined within the original scope of the study.

The sensitivity analysis compares the financial impact of these changes to the Base Case of the ShipperCo Scenario (i.e., RailCo + Railcars) for both 1 mbpd and 1.5 mbpd.

The parameters used in this sensitivity analysis are shown in the following table:

	ShipperCo	
Scenario (mbpd)	**1.0**	**1.5**
Environmental Assessment	5	5
Construction	4	4
Ramp Up	2	2
Full Operations	18	18
Total Duration	**29**	**29**
Debt/Equity Ratio	65% Debt / 35% Equity	
Cost of Debt	6.0%	
Cost of Equity	12.2%	
Weighted Average Cost of Capital	8.2%	
Cost Escalation (Capex & Opex)	3.0%	
Price Escalation	2.0%	
Salvage Value Based on Life in Years	50 Track 25 Signals & Communications 25 Rolling Stock & Equipment 25 Facilities	
Loaded Train Starts per Day	8	12
Operational Days per Year	336	329
Total Loaded Train Starts per Year	2,688	3,948
Total Barrels Hauled Per Year (Millions)	**336**	**494**
Total Barrels Hauled for Duration (Millions)	**6,381**	**9,372**

The Environmental Assessment duration was changed from 2 to 5 years while applying the same annual 2013 base costs over the additional years. This changed the total environmental cost from $228 M to $443 M. Previously $59 M was allocated to years 1 and 2, while $37 M allocated to years 3 through 5, for a total of about $228 M. In this sensitivity analysis $59 M was allocated to years 1 through 5, while $37 M allocated to years 6 through 9, for a total of about $443 M. All figures are in 2013 dollars.

The Construction duration was changed from 3 to 4 years but with the same total 2013 base cost allocated over 4 years.

The results of the sensitivity analysis are:

SHIPPERCO $2013/BARREL	Base	Extended	Difference	%
1 mbpd	$9.96	$10.60	$0.64	6.4%
1.5 mbpd	$8.14	$8.63	$0.49	6.0%

1.8 Derivation of Weighted Average Cost of Capital

This note explains how the weighted average cost of capital (WACC) was derived for the purpose of discounting the pre-tax profits under the ShipperCo and the RailCo financial analyses.

The pre-tax WACC was derived using the equation below:

(1) $\text{WACC} = K_d * D / (D + E) + K_e * E / (D + E)$, where

K_d = the cost of corporate debt (pre-tax), estimated at 6%
D = the market value of debt required to fund the project
E = the market value of equity required to fund the project, and
K_e = the cost of levered equity, estimated at 12.2%

Based on a debt/equity split of 65/35, this yields a WACC of 8.2% on a pre-tax basis. We examine below how each of the above elements of the WACC was derived in turn:

Cost of Debt (Kd)

The cost of corporate debt is intended to reflect the cost of raising debt for an entity such as RailCo or ShipperCo and takes into account the proposed capital structure of the entity. We estimated the cost of debt from two components:

- R_f = 3.0% (the risk-free rate),
  based on Government of Canada benchmark bond yields, specifically the average yield for 10+ year maturities (Bank of Canada website, accessed 9 Oct 2013)
- the market spread (over equivalent-term sovereign bonds) = 3% (or 300 basis points), which the bond market is likely to require to fund a venture such as ShipperCo or RailCo; this estimate was obtained from discussions with Canadian capital markets analysts familiar with bond market conditions for entities such as ShipperCo or RailCo. These discussions suggested that spreads could be as low as 220 to 250 basis points, based on corporate bond market conditions prevailing in recent months. Hence, we chose a conservative estimate of 300 basis points.

These two components yield a cost of debt of 6% on a pre-tax basis, which is a conservative estimate based on our approach to estimating the market spread.

Market Value of Debt

The market value of debt required to fund either RailCo or ShipperCo is estimated at 65% of total funds required.

Market Value of Equity

The market value of debt required to fund either RailCo or ShipperCo is estimated at 35% of total funds required. The resulting 65/35 debt/equity split is remains constant over the full period of analysis.

Cost of Levered Equity (Ke)

The cost of levered equity is derived from the Capital Asset Pricing Model (CAPM) equation below:

(2) $K_e = R_f + \beta_e * (R_m – R_f)$, where

R_f = the risk-free rate of return, at 3% as per above.

$R_m – R_f$ = the market risk premium, which is estimated at 7.82%

The market risk premium captures the difference between the rate of return on the market portfolio (i.e. a portfolio of shares replicating the returns of a local market index) and R_f. The risk premium was estimated from Ibbitson [add reference, pp. 7, 12] and consists of the long horizon equity risk premium (6.7%) and a size premium for a mid-cap corporate entity (1.12%).

β_e = levered equity beta.

The levered equity beta was estimated based on two sets of comparables: diversified utilities and pipelines and mid-stream corporate entities. In both cases, the average levered equity beta was 0.582, measured on a weekly basis from Bloomberg estimates and adjusted as per Merrill Lynch methodology.

The next step is to unlever the equity beta obtained from the comparables at the historical debt/equity ratio of the comparables and to relever at the debt/equity ratio of RailCo and ShipperCo.

We selected the two Pipeline and mid-stream comparables with the highest levered equity betas – AltaGas and Inter Pipeline, which had levered equity betas of 0.657 and 0.65 respectively. We derived the asset beta (or unlevered equity beta) for each comparable using the following formula:

(3) $\beta_a = \beta_e / [1 + (1 - T) * D / E]$, where

T = the marginal corporate income tax rate for the corporate entity

Canadian Energy Infrastructure Market Betas

Based on Bloomberg Estimates

	5-Year				3-Year			
	Weekly		Monthly		Weekly		Monthly	
	Raw	Adj.	Raw	Adj.	Raw	Adj.	Raw	Adj.
Diversified Utilities								
Canadian Utilities	0.280	0.520	0.033	0.355	0.216	0.478	0.056	0.371
Emera	0.407	0.605	0.243	0.495	0.448	0.632	0.137	0.425
Enbridge	0.344	0.563	0.163	0.442	0.304	0.536	-0.011	0.326
Fortis	0.446	0.630	0.195	0.463	0.462	0.641	0.164	0.443
TransCanada	0.408	0.605	0.248	0.499	0.287	0.525	0.110	0.406
Average	**0.377**	**0.585**	**0.176**	**0.451**	**0.343**	**0.562**	**0.091**	**0.394**
Pipelines & Midstream								
AltaGas	0.485	0.657	0.549	0.699	0.458	0.639	0.465	0.644
Enbridge Income Fund Holdings	0.331	0.554	0.172	0.448	0.176	0.451	0.206	0.471
Inter Pipeline	0.476	0.650	0.430	0.620	0.463	0.642	0.224	0.483
Pembina	0.317	0.545	0.143	0.429	0.285	0.523	0.143	0.429
Veresen	0.669	0.504	0.281	0.520	0.481	0.654	0.141	0.427
Average	**0.456**	**0.582**	**0.315**	**0.543**	**0.373**	**0.582**	**0.236**	**0.491**

Represents recommended beta data set for analysis.

0 *Adjusted betas adjusted as per Merrill Lynch; calculated as (2/3)*Raw Beta + (1/3)*1.00*

RBC Capital Markets

The resulting asset betas are 0.495 and 0.407 for AltaGas and Inter Pipeline respectively, calculated over the five-year period from 2008 to 2012, during which time the combined Alberta/Federal statutory corporate income tax rate was 27.6% (five-year average) and the average D/E ratio was 0.45 for AltaGas and 0.83 for Inter Pipeline. These ratios are based on the market value of equity and the book value of debt for the two companies. In principle, the debt instruments for each company should be valued on a market rather than book basis. However, a sample of the fair market values of some of the debt instruments suggested that these did not diverge significantly from book values.

We then used equation (3) above to re-lever the equity betas based on 65/35 debt/equity split appropriate for ShipperCo and RailCo. In this case, we used the 2012-13 combined Alberta/Federal corporate income tax rate of 25% (and the asset betas noted above). The result of this analysis yielded an equity beta of 1.18 for the AltaGas comparable and 0.97 for the Inter Pipeline comparable. We selected the 1.18 value as a conservative estimate.

Using the re-levered equity beta of 1.18 and the market risk premium of 7.82% yields a cost of equity of 12.2%.

Implications for RailCo Contractual Commitments and Dynamic vs Static Cost of Capital

In practice, the cost of equity depends on the stage of the project, the proportion of capacity which is contracted for, contract lengths and the credit quality of counterparties. As a result, some capital market specialists have suggested that the cost of equity (on a pre-tax basis) will tend to differ at each stage of the project based on the following indicative notes:

- Initial project development – 25%+
- Construction period –20-25% (assuming some short-term contracts already secured)
    - In the presence of some longer-term (5-10 year) contracts – 20%
- Operations period
    - With 1-5 year contracts accounting for 75% of capacity, assuming investment-grade counterparties – about 15%
    - With long-term contracts accounting for at least 75% of capacity and investment-grade counterparties – 12-15%

One potential implication is that the cost of capital may change over time for the purpose of the Discounted Cash Flow (DCF) analysis. However, this project is still at an early, pre-feasibility stage of planning. Hence, there remains limited clarity regarding the timing of each stage and how quickly the project can secure customer commitments. As a result, it is preferable at this stage to take a medium-to-longer term view of the project and rely on a static cost of capital.