Appendix A Direct Written Evidence of Steven J. Kelly, IHS Global Canada Limited

Trans Mountain Expansion Project
Direct Written Evidence of
Steven J. Kelly

Prepared For:

Trans Mountain Pipeline (ULC)

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Submitted by:

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TERMS OF USE

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ABBREVIATIONS AND ACRONYMS

ANS	Alaskan North Slope
B/D	Barrels per Day
C5+	Pentanes Plus
CAPP	Canadian Association of Petroleum Producers
CEAA	Canadian Environmental Assessment Agency
CLB	Cold Lake Blend
DilBit	Bitumen Blend, diluted with C5+
DOE	U.S. Department of Energy
EIA	U.S. Energy Information Administration
ERCB	Alberta Energy Resources Conservation Board
FCC	Fluid Catalytic Cracking
GHG	Greenhouse Gas
JRP	Joint Review Panel
KXL	Keystone XL Pipeline
LLS	Light Louisiana Sweet
NEB	National Energy Board
PADD	Petroleum Administration for Defense District
PGI	Purvin & Gertz, Inc.
RFO	Residual Fuel Oil
SCO	Synthetic Crude Oil
TMEP	Trans Mountain Expansion Project
VGO	Vacuum Gas Oil
WCS	Western Canadian Select
WTI	West Texas Intermediate

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INTRODUCTION

Q.1. Please state your full name, position and business address.

A.1. My name is Steven J. Kelly. I am a Vice President at IHS Global Canada Limited ("IHS"). I direct the Downstream Energy Consulting operations at the IHS office in Calgary, Alberta. Prior to IHS, I was Senior Vice President and Director at Purvin & Gertz Inc. ("Purvin & Gertz" or "PGI"). IHS acquired PGI in November 2011. My business address is Suite 200, 1331 Macleod Trail S.E., Calgary, Alberta, T2G 0K3.

Q.2. Please describe your educational and professional background.

A.2. I graduated with a Bachelor of Engineering degree in Chemical Engineering from McMaster University in Hamilton, Ontario in 1982. I obtained a Master of Engineering degree in Chemical Engineering from McMaster University, with specialization in process computer control in 1985, and a Master of Business Administration degree from the University of Calgary in 1998. I worked as a process engineer at the Sarnia and Scotford refineries of Shell Canada, and in a variety of operations and strategic planning roles at Shell Canada's Calgary head office. In 1996, I joined PGI's Calgary office as an Associate Consultant. I have worked at PGI (and IHS since November 2011) for a total of 17 years, including a four-year posting in the Purvin & Gertz office in London, UK. Much of my work at PGI/IHS has involved market studies for conventional crude oil, oil sands and refined products in North America and Europe. I have prepared and provided expert testimony on pipeline matters in Canada before the National Energy Board ("NEB"). I am a Professional Engineer, registered in Alberta.

Q.3. Please describe IHS and its Energy Insight consulting operations.

A.3. IHS is a global information company that provides comprehensive content, insight and expertise to business and government clients around the world. IHS has been providing information, independent analysis and insight to its customers for more than 50 years. IHS has been in business since 1959 and became a publicly traded company on the New York Stock Exchange in 2005. The company is headquartered in Englewood, Colorado, USA. As of September 2013 the company employs over 8,000 people worldwide. IHS Energy Insights Consulting offers industry and business advisory expertise across the upstream, midstream, downstream, and chemicals segments of the energy value chain.

Q.4. What is the purpose of your evidence in this proceeding?

A.4. Trans Mountain Pipeline ULC ("Trans Mountain") has proposed an expansion of its existing oil pipeline ("TMEP" or "the Project"). The proposed expansion would increase capacity of the current pipeline from 300,000 barrels per day ("B/D") to 890,000 B/D. As part of this application to the NEB ("the Application"), Trans Mountain engaged IHS to address various supply and market issues related to the Project. Specifically, IHS was asked to address the following questions:

1. If the TMEP is constructed as planned, is it reasonable to expect that the facilities will be highly utilized?

2. If the TMEP is built as planned, is it reasonable to expect that it will produce a benefit for Canadian producers in the form of higher netback prices for their crude oil production? What is the expected aggregate amount of economic gain to producers from the Project's development?

3. Would the TMEP provide access to new markets, and is access to these new markets a benefit to producers?

SUMMARY OF CONCLUSIONS

Q.5. Please summarize your conclusions.

A.5. IHS' major conclusions from this analysis are summarized below:

- If the TMEP project is constructed as proposed, IHS believes that the facilities will be utilized at a high rate. IHS forecasts continued growth in Western Canadian crude oil production over the forecast period to 2037. Marketed crude supply growth in Western Canada is likely to be mainly heavy crude grades. Based on our analysis of the potential markets for Western Canadian crudes in the Asia/Pacific region, and the outlook for crude balances, the crude shipped by TMEP may include both light and heavy grades.

- IHS concludes that as one of several major export pipeline projects, the TMEP would provide benefits for Western Canadian crude producers. The annual revenue benefits from new pipeline development are estimated at about $6 billion (constant 2012 US) in 2018, increasing with production to about $11 billion (constant 2012 US) by 2030 in the Base Case. Total estimated benefits attributable to TMEP are $37 billion through the forecast period.[1] These benefits would be realized through higher netback prices for heavy crude oil production, associated with the avoidance of discounted crude prices in the future when supplies exceed takeaway pipeline capacity.

- In addition to the above general benefits, TMEP would provide structural access to new markets in the Asia/Pacific region. IHS has addressed the potential for market development in California and selected countries in Asia, based on existing refinery capabilities, expected future crude demand and the need for imported crudes.

[1] Benefits attributable to TMEP equate to 26.6 percent of the total estimated benefits for export pipeline capacity expansions.

Producers with capacity on TMEP would have the opportunity to realize higher netback prices on production that is priced in the Asia/Pacific region rather than the U.S. Gulf Coast region. As compared to exports to the U.S. Gulf Coast, exports to California are expected to provide a $3 to $4 per barrel (constant 2012 US) netback premium to Canadian producers, and exports to Asia/Pacific markets are expected to provide a $2 per barrel netback premium. These benefits would apply from 2018 through the end of the forecast period. The benefits associated with higher netbacks from markets in Asia are estimated at $8 billion over the forecast period.[2] Total benefits attributable to TMEP are $45 billion, including both general industry benefits and higher netback prices on deliveries to Asia.

- The benefits calculated for export pipeline capacity expansion are considered conservative, because no allowance has been made for the possibility of extraordinary discounts on Canadian crude re-emerging in the future. The calculated benefits are also considered conservative because the optionality benefits provided by the TMEP were not quantified and included in the analysis.

- The Project would provide optionality benefits and market diversity for its shippers, in a market characterized by substantial uncertainty. As demonstrated by the experience in Canada from 2010 to present, logistical constraints in reaching the highest-value export markets can cost the industry tens of billions of dollars per year.[3] Furthermore, there is no certainty regarding what the highest value market will be over the forecast period, so ensuring that multiple markets are accessible offers significant value to producers.

SUMMARY OF SUPPORTING ANALYSIS

- IHS forecasts continued growth in Western Canadian crude oil production, with total crude production growing at a 3.0 percent compound annual average growth from 2013 to 2037. This growth trend results in 3.43 million B/D of incremental production over the same period. The Base Case forecast has been compared to the most recent production forecasts of the Canadian Association of Petroleum Producers ("CAPP"), the NEB and the Alberta Energy Resources Conservation Board ("ERCB"), and has been found to be generally consistent with them, although below the CAPP forecast for the years after 2020. IHS forecasts marketed heavy crude supply (which accounts for upgrading and diluent addition) to increase by 4.30 million B/D between 2013 and 2037.

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[2] These benefits would be realized on volumes shipped to Asia and priced against Middle East crude imported into the region. The benefits for TMEP shippers are based on half of the TMEP firm commitments (equal to 707,500 B/D ÷ 2 = 353,750 B/D) being priced in China rather than in the U.S. Gulf Coast for the period 2018 to 2037.

[3] IHS estimates that Western Canadian producers would have received between $15-19 billion in incremental revenue in 2012, had they been able to bring their crude oil to other markets.

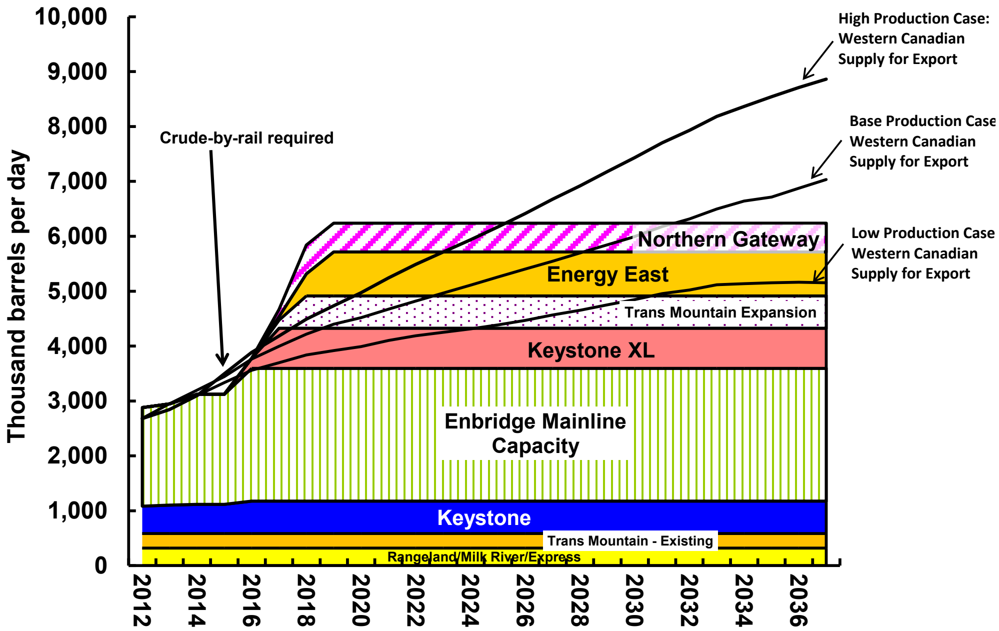
- Western Canadian crude currently serves markets in Canada, the U.S., and offshore locations. IHS forecasts that total crude demand by U.S. refineries will remain relatively stagnant through the end of the decade, and that their demand will decline thereafter. Canadian crude will account for a growing share of U.S. crude consumption. Other markets may be served via the Canadian West Coast and the Canadian East Coast. Refineries in Canada, the U.S. and Asia are potential disposition outlets for Western Canadian crude and U.S. northern tier crude. The increasing need for imported crude of all types in Asia is the basis for interest by Asian companies in Canadian oil sands crudes.

- To assess the aggregate need for and benefits of incremental pipeline capacity, IHS analyzed and compared two scenarios. The "Expansion Scenario" is premised on all planned pipeline projects[4] coming on line in the time period to 2018, as proposed by the project sponsors. For comparison, the "Reference Scenario" assumes that only projects currently in construction and the Keystone XL Pipeline are developed.

- Figure 1 compares the Base Case forecast of crude supply for export in Western Canada with the future outlook for pipeline takeaway capacity in the Expansion Scenario, over the 2013 to 2037 period. For the presentation in Figure 1, all pipeline projects are assumed to be available at their nameplate capacity. IHS estimates that all of the expansion capacity is needed to meet projected crude production after 2026. Before this expansion capacity comes on line, rail shipments will also be required to meet the shortfall in pipeline capacity. Rail shipments are forecast to peak in 2015. By 2030, rail shipments would again begin to be required to accommodate growth in crude production.

[4] The projects include those currently under construction, as well as TransCanada Pipeline's Keystone XL Pipeline ("KXL") in 2016, the Trans Mountain Expansion Project in 2017, TransCanada Pipeline's Energy East project ("Energy East") in 2017 and Enbridge's Northern Gateway project in 2018.

Figure 1 - Western Canadian Supply for Pipeline Export vs. Pipeline Capacity



Source:IHS

- The Expansion Scenario indicates that rail deliveries will be required until 2016, at which time Enbridge expansions and Keystone XL absorb the growth in marketable crude supply. TMEP, Energy East and Northern Gateway are assumed to come on in 2017 and 2018, and thereby reduce the need for rail. Term commitments on new pipeline projects suggest that the crude available for spot deliveries to markets in the U.S. Midwest and rail will be in short supply for several years, between about 2018 and 2022.

- Figure 1 also compares Western Canada takeaway capacity with crude supply in two alternative production cases. In the Expansion Scenario with slower bitumen production growth (a case we have defined as the Low Production case), IHS estimates that pipeline capacity additions will be adequate to keep up with crude supply growth for the forecast period. In the Expansion Scenario with increased bitumen and tight oil production growth (defined as the High Production case), IHS estimates that pipeline capacity additions will fall short of crude supply growth before 2025.

- Takeaway capacity in the Reference Scenario (not shown in Figure 1) includes only pipeline projects currently under construction and development of the Keystone XL pipeline in 2016. In this scenario, takeaway capacity would be inadequate to clear the supply of heavy crude by pipeline throughout the forecast period.

- IHS believes that development of export pipelines would contribute to a reduction in the use of rail transportation for Western Canadian crude oil. Pipeline capacity additions over the next several years are expected to reduce the dependence on rail transportation for light and heavy crude oil, until such time as crude production once again exceeds pipeline takeaway capacity. The use of pipeline capacity instead of rail transportation is conservatively estimated to provide an increase in producer netbacks of $5-6 per barrel (constant 2012 US) during the forecast period.

Q.6. Please summarize the analysis you conducted in order to answer the questions indicated above.

A.6. **Supply/Infrastructure Development**

IHS developed the Expansion Scenario and the Reference Scenario for infrastructure development, as described above. In addition to the Base Case supply outlook, IHS developed alternative production and supply cases to analyze how different production growth rates for bitumen and light crude might affect the results. These cases are referred to as the “Low Production” and “High Production” cases. The Low Production case includes a premise of lower bitumen production and supply, while the High Production case includes a premise of higher bitumen production and supply, and higher U.S. tight oil production. The Low Production and High Production cases have been examined under the premises of the Reference Scenario and Expansion Scenario for infrastructure development.

Crude Prices and Producer Netbacks

IHS applied its standard methodologies to the analysis of Canadian crude prices under the different production and infrastructure development cases defined above. Canadian crude prices are established in the markets they serve, based on refining value differentials to appropriate competing crude oils. Netback prices are set by the market price, less applicable transportation costs from the point of production. The clearing market sets the price for the marginal barrel. In our methodology, Dated Brent is indicative of world crude prices, and is used as the basis for other regional crude price forecasts. For this analysis, IHS developed price forecasts for oil sands crudes (Cold Lake bitumen blend and Syncrude SSP), which are based on competition with competing crudes in Midwest, West Coast and Asia/Pacific markets. Refineries on the West Coast and in Asian markets would gain increased access to Canadian crudes if TMEP is constructed as proposed.

Industry Benefits

IHS estimated industry benefits associated with higher price realizations for Canadian heavy crudes by comparing producer revenue (on a per barrel basis) from pipeline and rail transportation. In general, the netback price for Canadian heavy crude blends would be higher if the netback price is established by pipeline rather than rail transportation, since the cost to move crude oil by rail is typically higher than the cost to move crude oil by pipeline. IHS estimated total revenue benefits by multiplying the unit revenue increase by the total volume of Western Canadian heavy crude supply. Following the startup of the export pipelines in the Expansion Scenario, increased revenues should be expected to continue until Canadian supply once again exceeds pipeline takeaway capacity, and the netback reverts to a rail transportation basis. In the Reference Scenario, producer revenue would be reduced by the amount of the difference between pipeline and rail transportation for the period of time that rail is used as the market clearing mechanism.

Q.7. Which sources did IHS rely on for preparation of its evidence?

A.7. In preparing its evidence, IHS reviewed Application material provided by Trans Mountain. Regulatory filings considered to be relevant to this proceeding were also reviewed. Public information and IHS' own proprietary models and databases were utilized in preparation of the IHS analysis. IHS reviewed other available publicly available information and forecasts pertaining to Canadian oil production and demand, as prepared by industry associations, regulators, public companies and other organizations.

DEVELOPMENT OF THE IHS ANALYSIS

Q.8. Please explain the Base Case supply/demand outlook in more detail.

A.8. The Base Case supply outlook takes into account the following key premises:

- IHS crude price and light/heavy differential forecasts
- IHS North American regional crude production forecasts (Q3 2013)
- IHS outlook for crude market demand (type and volume) and interregional trade
- Rail infrastructure development for crude export is based on existing in-service capacity and proposed expansions

The Base Case production outlook is summarized in Figure 2.[5] IHS forecasts that growth in oil sands crude production will offset a decline for conventional crude. Between 2013 and 2037, the Base Case forecast for Western Canada crude production calls for an increase of 3.43 million B/D. Heavy crude production, including bitumen, accounts for the majority of this increase. Bitumen production growth is forecast to average 118,000 B/D per year between 2013 and 2037. Figure 2 also presents the most recent forecasts developed by CAPP and the NEB, for comparison to the Base Case.

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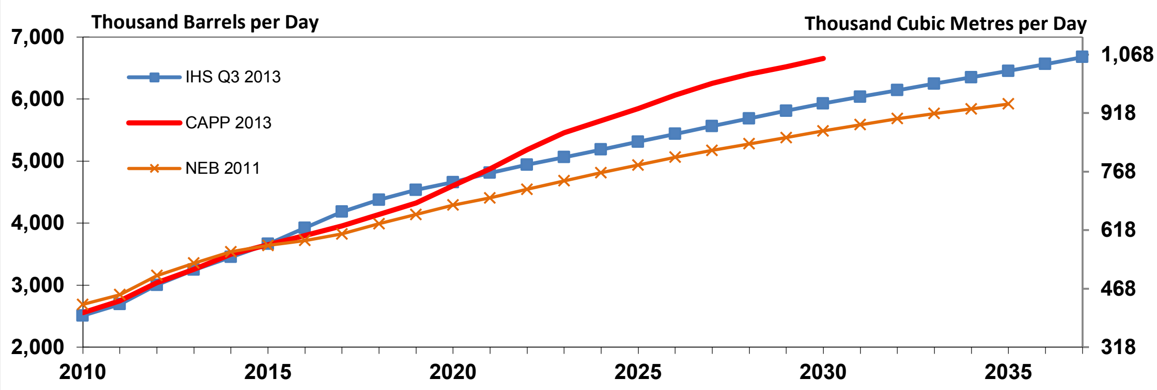
[5] Refer to Appendix A, which supplements this presentation by including more details of the IHS analysis.

FIGURE 2
WESTERN CANADA TOTAL CRUDE PRODUCTION FORECAST



The Base Case disposition forecast is predicated on total crude demand by U.S. refineries remaining relatively stagnant through the end of the decade, at between 15.5 and 16 million B/D. Demand by U.S. refineries is forecast to decline thereafter. Despite the lack of demand growth in U.S. refining markets, Canadian crude exports to the U.S. are expected to approximately double from 2013 to 2035, representing growth of more than 2.5 million B/D. As shown in Table 1, Canadian crude exports will account for a growing share of U.S. crude consumption, and will contribute to a dramatic drop in imports from other countries. This will occur despite an increase in U.S. crude production which is forecast to continue through the early part of the next decade, due to technological advances that have unlocked the potential of certain shale oil resources.

TABLE 1
TOTAL U.S. CRUDE OIL SUPPLY / DEMAND
(Thousand Barrels per Day)

	2012	2013	2014	2015	2020	2025	2030	2035
Total Runs	15,020	15,264	15,548	15,715	15,860	15,338	14,956	14,574
Total Capacity	17,776	17,689	17,714	17,743	17,743	17,743	17,743	17,743
% Capacity Utilization	84	86	88	89	89	86	84	82
Production	6,521	7,336	7,549	7,768	8,359	8,079	7,593	7,513
Canadian Imports	2,279	2,522	2,690	2,909	3,571	4,270	4,550	5,092
Other Imports	6,133	5,522	5,457	5,263	4,221	3,336	3,109	2,248
Total Imports	8,412	8,043	8,147	8,172	7,793	7,606	7,658	7,340
Total Supply	14,879	15,264	15,548	15,715	15,840	15,338	14,956	14,574

Q.9. Please explain the Low Production and High Production case outlooks in more detail.

A.9. The Base Case supply of bitumen and conventional light crude is adjusted in the Low Production case and the High Production case. The Low Production case assumes lower Alberta bitumen production growth relative to the Base Case, by 55,000 B/D per year on a cumulative basis between 2015 and 2037. The growth rate in bitumen production incorporated into the Low Production case forecast is half of the average annual growth rate incorporated into the Base Case forecast. The High Production case assumes higher Alberta bitumen production growth relative to the Base Case, by the same amount (55,000 B/D per year on a cumulative basis) over the forecast period. The High Production case also includes a premise of higher production of U.S. light crude over the forecast period. Over the forecast period from 2015 to 2037, the cumulative changes in bitumen production amount to a 1.265 million B/D decrease in the Low Production case, and a 1.265 million B/D increase in the High Production case. In each case, imported condensate for bitumen blending is assumed to be available from local production, diluent import pipelines and supplementary rail deliveries.

Low Production case outlook

- Lower bitumen production forecast versus the Base Case, which may be the result of wider light/heavy price differentials, higher project costs or other factors affecting bitumen production
- Base Case forecast of tight oil production
- Base Case outlook for crude market demand (type and volume) and interregional trade to balance

High Production case outlook

- Higher bitumen production forecast versus the Base Case, which may be the result of narrower light/heavy price differentials, lower project costs or other factors affecting bitumen production
- Higher forecast of tight oil production
- Base Case outlook for crude market demand (type and volume) and interregional trade to balance

TABLE 2
POTENTIAL INDUSTRY BENEFITS OF EXPORT PIPELINE CAPACITY

	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037
Base Case																				
Heavy Crude Supply, MB/D	3,193	3,372	3,485	3,665	3,833	3,995	4,159	4,323	4,488	4,656	4,820	4,986	5,153	5,316	5,479	5,644	5,812	5,985	6,140	6,306
Pipeline vs. Rail Netback (1)																				
Per Barrel Benefit (2012 $/B)	5.00	5.08	5.14	5.20	5.25	5.30	5.36	5.40	5.44	5.49	5.54	5.59	5.64	5.69	5.73	5.78	-	-	-	-
Total Benefit (2012 Billion $)	5.8	6.2	6.5	7.0	7.3	7.7	8.1	8.5	8.9	9.3	9.8	10.2	10.6	11.0	11.5	11.9	-	-	-	-
TMEP Heavy Crude to Asia, MB/D (2)	213	354	354	354	354	354	354	354	354	354	354	354	354	354	354	354	354	354	354	354
Asia vs. US Gulf Coast Netback																				
Per Barrel Benefit (2012 $/B)	1.76	2.19	2.49	2.49	2.32	2.21	2.12	1.99	1.98	1.97	1.95	1.94	1.82	1.81	1.80	1.80	7.61	7.65	7.68	7.72
Total Benefit (2012 Billion $)	0.1	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.2	0.2	0.2	0.2	1.0	1.0	1.0	1.0
Low Production Case																				
Heavy Crude Supply, MB/D	2,867	2,964	2,995	3,124	3,226	3,307	3,390	3,475	3,559	3,646	3,730	3,816	3,903	3,987	4,070	4,155	4,242	4,328	4,413	4,499
Pipeline vs. Rail Netback (1)																				
Per Barrel Benefit (2012 $/B)	-	-	5.14	5.20	5.25	5.30	5.36	5.40	5.44	5.49	5.54	5.59	5.64	5.69	5.73	5.78	5.82	5.86	5.90	5.95
Total Benefit (2012 Billion $)	-	-	5.6	5.9	6.2	6.4	6.6	6.8	7.1	7.3	7.5	7.8	8.0	8.3	8.5	8.8	9.0	9.3	9.5	9.8
TMEP Heavy Crude to Asia, MB/D (2)	188	354	354	354	354	354	354	354	354	354	354	354	354	354	354	354	354	354	354	354
Asia vs. US Gulf Coast Netback																				
Per Barrel Benefit (2012 $/B)	1.76	2.19	2.49	2.49	2.32	2.21	2.12	1.99	1.98	1.97	1.95	1.94	1.82	1.81	1.80	1.80	1.79	1.78	1.78	1.77
Total Benefit (2012 Billion $)	0.1	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2
High Production Case																				
Heavy Crude Supply, MB/D	3,519	3,780	3,975	4,264	4,528	4,770	5,015	5,260	5,505	5,753	5,997	6,243	6,489	6,733	6,976	7,221	7,469	7,716	7,961	8,207
Pipeline vs. Rail Netback (1)																				
Per Barrel Benefit (2012 $/B)	5.00	5.08	5.14	5.20	5.25	5.30	5.36	-	-	-	-	-	-	-	-	-	-	-	-	-
Total Benefit (2012 Billion $)	6.4	7.0	7.5	8.1	8.7	9.2	9.8	-	-	-	-	-	-	-	-	-	-	-	-	-
TMEP Heavy Crude to Asia, MB/D (2)	238	354	354	354	354	354	354	354	354	354	354	354	354	354	354	354	354	354	354	354
Asia vs. US Gulf Coast Netback																				
Per Barrel Benefit (2012 $/B)	1.76	2.19	2.49	2.49	2.32	2.21	2.12	7.39	7.42	7.46	7.49	7.53	7.46	7.50	7.54	7.57	7.61	7.65	7.68	7.72
Total Benefit (2012 Billion $)	0.2	0.3	0.3	0.3	0.3	0.3	0.3	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0

Note: (1) Rail netback price assumes DilBit transportation from Edmonton to US Gulf Coast. Excludes rail car lease costs.
(2) Benefit accrues to shippers with capacity on West Coast pipeline projects. Benefits shown assume 50% of TMEP firm capacity are deliveries to China.

NETBACK PRICING AND BENEFITS ANALYSIS

Q.10. What impact is the expansion of pipeline capacity expected to have on heavy crude netback prices in Western Canada, and what are the aggregate benefits?

A.10. TMEP, as one of the pipeline capacity expansion projects included in the Expansion Scenario, is expected to contribute to significantly higher heavy crude netback prices for Canadian oil producers. As shown in Table 2, below, netback prices for heavy crude are estimated to be $5 to $6 per barrel (constant 2012 U.S.) higher as a general consequence of the development of new pipeline capacity. The netback price benefit is attributed to the lower cost of pipeline transportation for heavy crude to the assumed clearing market location (the U.S. Gulf Coast), compared to the cost of rail transportation.[6] This is considered a conservative estimate, in part because the rail transportation cost estimate excludes rail car lease costs.

Table 2 summarizes the producer revenue benefits for the three supply cases developed for this analysis. The annual revenue benefits from pipeline development in the Expansion Scenario are about $6 billion (constant 2012 US) in 2018, increasing with production to about $11 billion (constant 2012 US) by 2030 in the Base Case. The benefits for heavy crude producers would be expected to continue until such time that the balance indicates a need for additional pipeline capacity for Western Canadian crude. This would occur late in the forecast period.

Annual benefits for the Expansion Scenario would be of a smaller magnitude in the Low Production case, and would be expected to start later due to lower bitumen production growth. Annual benefits would be higher in the High Production case, and would commence sooner compared to the Base Case. Pipeline capacity expansions would be full in the High Production case before 2025.

In aggregate, higher netback prices for heavy crude equate to about $140 billion U.S. of producer benefits in the Base Case (on a constant 2012 US, undiscounted basis) over the 2017 to 2037 time period. In the Low Production case, the aggregate benefits are estimated at about $138 billion U.S. over the same time period. In the High Production case, aggregate benefits are estimated to be less, at around $57 billion U.S. because the pipeline projects reach capacity sooner, reducing prices to a rail-equivalent netback from the U.S. Gulf Coast. However, the estimated benefit in the High Production case is considered very conservative, because it excludes any extraordinary discounts on Canadian heavy crude which may result when pipelines and rail export facilities reach capacity. As noted above, the annual revenue loss in 2012 estimated by IHS (equal to

[6] The analysis shown is based on rail delivery of DilBit, which may or may not be the form that bitumen is shipped by rail. Other blends of bitumen are possible, including blends with lesser amounts of diluent or no diluent at all.

$15-19 billion) provides an indication of the potential impact of having inadequate pipeline and rail capacity.

Q.11. What is the estimated benefit attributable to TMEP?

A.11. As described above, IHS completed the analysis by assuming that TMEP, Energy East and Northern Gateway all achieve commercial operation in the 2017-2018 timeframe, consistent with announced development plans. Therefore, IHS concludes that TMEP, as part of an aggregate expansion of capacity, contributes to these higher netback prices. TMEP represents 26.6 percent of the assumed capacity additions,[7] and it is assumed to produce at least the same percentage of the aggregate benefits.

In addition, the analysis also indicates that TMEP represents a path to higher netback markets, and can be expected to produce an above-average level of netback benefits. Further, if one or more of the other new pipeline projects were assumed to not go forward, the benefits derived from TMEP (expressed per unit of capacity) would increase. This is because the initial level of underutilized capacity would decrease. Therefore, the apportioned benefits for TMEP are considered to represent a conservative estimate of the likely standalone benefits of the Project. Further, the calculated benefits are also considered conservative because the optionality benefits provided by the TMEP were not quantified and included in the analysis.

Benefits attributed to the TMEP are estimated as follows, based on the overall benefits for pipeline capacity expansion and the TMEP share of capacity. In the Base Case, TMEP would be attributed $37.4 billion US of the total industry benefits over the 2018 to 2037 time period. In addition, TMEP would produce benefits of about $8 billion U.S. due to the realization of higher netback prices for crude priced in Asia rather than the U.S. Gulf Coast. Total benefits attributable to TMEP are therefore about $45 billion U.S. over the forecast period.

Q.12. What causes this increase in netbacks for oil sands producers?

A.12. The price of Canadian heavy crude has been discounted below price parity against comparable crudes (such as Mexican Maya at the U.S. Gulf Coast) for much of the last decade. This has been the case, even though these crudes are similar in quality and have nearly equivalent values in coking refineries. The price discount suggests that the supply of Canadian heavy crudes has exceeded demand in their main markets north of the U.S. Gulf Coast, which has led producers to seek access to other markets. For example, the TMEP targets large markets in the Asia/Pacific region, to expand the market for Canadian heavy crudes.

[7] TMEP capacity is 590,000 B/D, Energy East capacity is 1.1 million B/D, and Northern Gateway capacity is 525,000 B/D.

The IHS price forecast is premised on Canadian heavy crude being priced to clear the market at the U.S. Gulf Coast beginning in 2016. The increase in the netback price (after elimination of extraordinary discounts) is consistent with Canadian heavy crude reaching U.S. Gulf Coast parity against Maya crude. IHS expects this pricing to be realized because new pipeline capacity will provide structural access to this large refining market. Other pipeline projects to North American markets, such as the Enbridge Line 9 project and the Enbridge Gulf Coast Access project, to the extent they ship heavy crude, should allow the price of Canadian heavy crude to avoid extraordinary discounts in future.

TMEP is one of several projects that target delivery of a large volume of Canadian crude to new markets. The expansion of pipeline capacity is expected to strengthen the price of Canadian heavy crude in Alberta. By providing diversification and new market access for Canadian heavy crudes, infrastructure developments such as those considered in the Expansion Scenario should ensure that extraordinary discounts are avoided in future.

Q.13. Please discuss the sensitivity of the estimated aggregate benefits associated with pipeline expansions?

A.13. The benefits associated with expansion of export pipeline capacity may be categorized as follows:

- Improved netback for pipeline versus rail delivery
- Higher netback realized from offshore crude pricing

The first of these benefits arises from the avoidance of a price discount when supplies of heavy crude exceed the takeaway capacity on available pipelines. We have conservatively modelled this situation using a rail delivery netback for Western Canadian heavy crude, which would result in a lower netback price in Alberta compared to a pipeline netback. As shown in Table 2, this situation arises in the Base Case after 2033, due to increased supply of heavy crude.

The second source of benefits would accrue to shippers on a pipeline that provides capacity to markets with higher potential netbacks. For example, TMEP would provide access to large and growing markets in California or Asian countries. The netback price for crude valuation in California or China (based on expected Middle East refining parity relationships) is estimated to be higher than the U.S. Gulf Coast price for the duration of the forecast. The higher netback price would be realized by TMEP shippers, who could expect to achieve the regional parity price. Similar benefits may be available to shippers on other export pipelines.

A shift in the clearing market location from U.S. Gulf Coast to a higher valued market may occur with the startup of TMEP and other pipeline projects. However, we view this as an unlikely outcome. We believe that (for example) a Midwest refiner seeking supply of heavy crude after startup of the major export pipeline projects may be required to bid supplies away from committed shippers on such pipeline projects. The diversion of heavy crude from the large U.S. Gulf Coast market - potentially the most likely source of supply for the Midwest refiner - would require the Gulf Coast refiner to, in turn, secure supply from other sources. TMEP and other projects, which would allow Canadian crude to reach new market regions, would also create the possibility for Gulf Coast refiners to attract crudes away from current suppliers to those same regions. The net result would be a more efficient trade balance for heavy crude, but not a fundamental shift in the pricing mechanism.

Higher crude prices resulting from export pipeline expansion would increase revenues for Canadian heavy crude producers. Heavy crude producers would be expected to realize an increase in the heavy crude price of between $5-6 per barrel by realizing a pipeline netback price rather than a rail netback price, as discussed above and shown in Table 2. Although the price comparison is specifically for Cold Lake Blend versus Maya, the same level of discounting is assumed to be applicable to other Canadian heavy crudes including other DilBit streams, conventional heavy crudes and blends such as Western Canadian Select ("WCS"), since prices for Canadian heavy crudes track each other more than the Maya price.

The benefits calculated for export pipeline capacity expansion are considered conservative for several reasons. No allowance has been made for the possibility of extraordinary discounts on Canadian crude re-emerging in the future. Although rail could be utilized to provide export capacity, growth in bitumen supply may outpace rail capacity additions. This is analogous to the situation in much of the last decade, in which Canadian bitumen was subject to extraordinary discounts due to inadequate export capacity in pipelines. Further, the optionality benefits provided by the TMEP were not quantified or included in the analysis.

Similar impacts may also apply to light synthetic crudes if supply exceeds demand in the Midwest. However, no allowance has been made for these volumes in our analysis, since IHS does not anticipate that supply of sweet SCO will exceed demand in accessible North American markets. While they may deliver some light crude to Asia/Pacific markets, the new pipeline capacity serving these markets is expected to be primarily used for heavy crude volumes.

Certain factors could negatively affect producer revenues, and would act to offset the revenue gains outlined above for Canadian producers. For example, "ship-or-pay" costs could be incurred for underutilized term commitments, or temporarily higher tolls may be incurred on common carrier pipelines due to offloading of these systems. However, in our opinion, these costs and uncertainties would be far less than the expected revenue gains, resulting in significant net benefits to the Canadian producing industry.

Q.14. Describe in more detail the results for the alternative supply cases, including specific discussion of the Trans Mountain Expansion Project.

A.14. Following is a summary description of the cases developed for this project.

Base Case

In the Base Case under the Expansion Scenario premises, a tighter supply/demand crude balance will be realized in 2017 and 2018, particularly for heavy crude. The Expansion Scenario results suggest that for several years, availability of crude for spot deliveries to markets such as the U.S. Midwest will be limited as new pipeline projects divert supply to other markets. The use of rail for crude transportation is expected to be largely reduced or eliminated, as the pipeline project startups are adequate to absorb available supplies. This situation is forecast to persist until at least the end of the next decade. Industry benefits would accrue from the realization of pipeline netback prices from the U.S. Gulf Coast, rather than rail netback prices.

For shippers on export pipeline projects, the potential exists for higher netback prices on crude sold in newly accessible markets, such as the Asia/Pacific region. IHS estimates that regional netback prices based on refining parity valuation would be higher in the Asia/Pacific region than the price realized from the U.S. Gulf Coast.

The Base Case under the Reference Scenario premises (without TMEP, Energy East and Northern Gateway) suggests that lower netback prices would continue due to realization of rail transportation economics. In our analysis, we estimate that the lower (rail-equivalent) netback price would occur through much of the forecast period, assuming that rail capacity would expand to handle the additional production. If existing rail loading capacity were in fact to become fully utilized, this could lead to a re-emergence of extraordinary discounts on Western Canadian crude. The recent historical period demonstrates that the extent of price discounting that could result in this situation cannot be predicted with any certainty.

Low Production Case

In the Low Production case under the Expansion Scenario premises, development of the major export pipeline projects would contribute to a significantly tighter supply/demand balance for heavy crude. Cumulative takeaway commitments on each of the major pipelines would be substantial. As a result, we estimate that the remaining supply of crude for spot deliveries to markets such as the U.S. Midwest would be limited for an extended period. The major export pipeline projects may not be required by their proposed in-service dates based on the supply/demand balance, so a phased approach may be needed to balance takeaway capacity with available crude supply. The use of rail for crude transportation is not forecast to be needed in this case. The tight balance situation would persist through the end of the forecast period. As in the Base Case, industry benefits would accrue from realization of spot pipeline netback prices from the U.S. Gulf Coast.

High Production Case

In the High Production case under the Expansion Scenario premises, the major export pipelines would directionally help balance Western Canadian crude markets when they start up between 2016 and 2018. The remaining supply of crude for spot deliveries to markets such as the U.S. Midwest are more ample than the Base Case, and are seen as generally being adequate for the needs of refineries in this region, despite the diversion of crude to the new pipelines. The use of rail for crude transportation may be needed in this case, which suggests that additional pipeline capacity may be required to maintain the market balance.

Q.15. Have you prepared a report providing more details of your analysis of the need for and expected benefits derived from the development of additional pipeline capacity?

A.15. Yes, I have. Appendix A presents the IHS analysis, which is based on the fundamental supply and market analysis completed for this assignment. Appendix A addresses the following topics:

I. Western Canada & U.S. Northern Tier Crude Oil Production
II. North American Crude Oil Market Overview
III. Asian Crude Oil Market Overview
IV. Canadian Crude Oil Export Pipeline Capacity & Utilization
V. Crude Oil Pricing

Q.16. Does this conclude your evidence?

A.16. Yes.

APPENDIX A

I. WESTERN CANADA & U.S. NORTHERN TIER CRUDE OIL PRODUCTION

Crude oil production in Western Canada includes crude produced from both conventional and oil sands resources. Conventional crude oil production includes light crude oil in Alberta, British Columbia, Saskatchewan, Manitoba and the Northwest Territories; heavy crude oil in Alberta and Saskatchewan; and, pentanes plus ("C5+") or condensate in Alberta and British Columbia. Oil sands crude includes bitumen and synthetic crude oil ("SCO"), which is produced by any of a number of upgrading processes. In 2012, total crude oil production in Western Canada was approximately 3.0 million B/D. Of this total, conventional crude oil and condensate production is estimated at 1.23 million B/D while oil sands production is estimated at 1.77 million B/D.

Crude oil production in the U.S. northern tier includes light crude produced from conventional and shale resources in several states. The main crude producing states in the U.S. northern tier are North Dakota and Montana. In 2012, total crude oil production from these two states was 735,000 B/D.[8] Of this total, North Dakota production was 663,000 B/D and Montana production was 72,000 B/D.[9] Combined production from North Dakota and Montana has risen sharply, up from 131,000 B/D in 2000 and 188,000 B/D in 2005.[10]

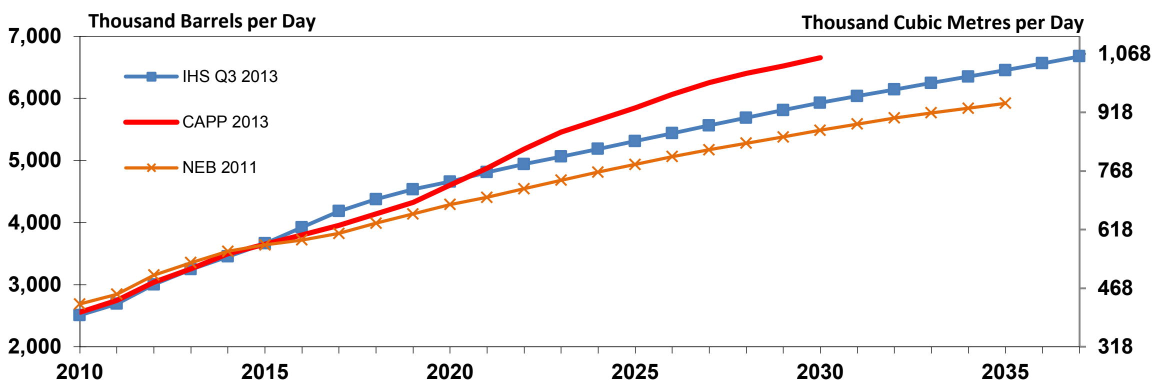
I-1. WESTERN CANADIAN PRODUCTION

IHS forecasts total crude production in Western Canada to increase through 2037. The Base Case forecast for this report was prepared in the third quarter of 2013. Refer to Figure A-1, where the IHS forecast is compared with available forecasts from the Canadian Association of Petroleum Producers ("CAPP") and the National Energy Board ("NEB"). Each of these forecasts calls for production increases for Western Canadian crude. The Base Case forecast shows an increase in Western Canada crude production of about 2.7 million B/D between 2013 and 2030, from 3.25 million B/D to 5.93 million B/D. The CAPP 2013 forecast[11] shows a higher absolute increase of about 3.4 million B/D between 2013 and 2030, from 3.26 million B/D to 6.65 million B/D of production.

[8] U.S. Energy Information Administration crude oil production data, http://www.eia.gov/dnav/pet/TblDefs/pet_crd_crpdn_tbldef2.asp, accessed on 8 September 2013.
[9] U.S. Energy Information Administration crude oil production data, http://www.eia.gov/dnav/pet/TblDefs/pet_crd_crpdn_tbldef2.asp, accessed on 8 September 2013.
[10] U.S. Energy Information Administration, http://www.eia.gov/dnav/pet/pet_crd_crpdn_adc_mbblpd_a.htm, accessed on 10 July 2013.
[11] CAPP, "Crude Oil Forecast, Markets & Pipelines", June 2013

The NEB 2011 Reference Case forecast[12] calls for an increase of 2.57 million B/D between 2013 and 2035, from 3.36 million B/D to 5.92 million B/D.

FIGURE A-1
WESTERN CANADA TOTAL CRUDE PRODUCTION FORECAST



For this report, IHS prepared two alternative production outlooks, which incorporate changes in key aspects of the production forecast. A Low Production case is premised on lower bitumen production growth, and a High Production case is premised on higher conventional light crude and bitumen production growth. These adjustments are discussed in more detail later.

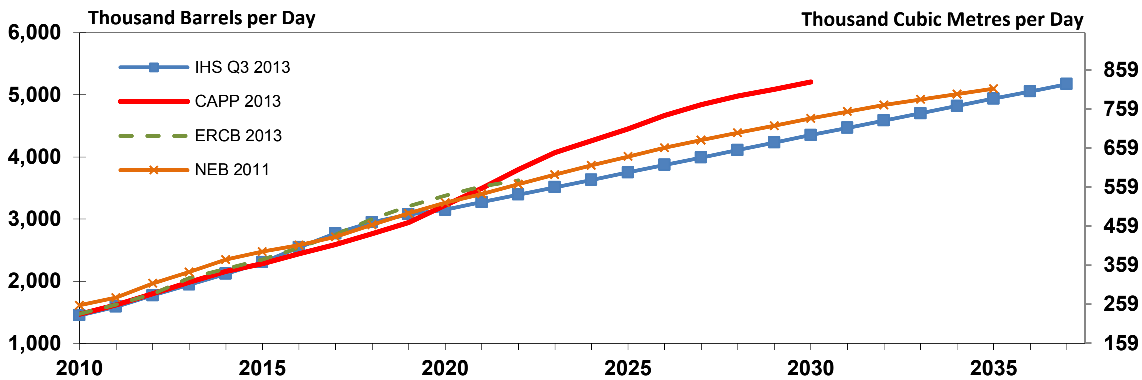
Oil Sands Production

Oil sands production includes mining and in-situ production of bitumen. IHS forecasts oil sands production to increase through 2037, and to account for the majority of the overall increase in Canadian crude production. Figure A-2 compares the Base Case forecast of oil sands production with the CAPP forecast. Figure A-2 also shows the oil sands production forecasts prepared by the NEB and the Alberta Energy Resources Conservation Board ("ERCB").[13] The current ERCB forecast extends to 2022. The IHS forecast for 2022 is 230,000 B/D below the ERCB forecast. The ERCB forecast is higher than the CAPP 2013 forecast until 2021. By 2022, the IHS forecast of oil sands production reaches 3.4 million B/D, which is about 406,000 B/D below the CAPP 2013 forecast.

[12] National Energy Board, "Canada's Energy Future: Energy Supply and Demand Projections to 2035", http://www.neb-one.gc.ca/clf-nsi/rnrgynfmtn/nrgyrprt/nrgyftr/2011/nrgsppldmndprjctn2035-eng.pdf, November 2011.

[13] Alberta Energy Resources Conservation Board ("ERCB") ST98-2013, "Alberta's Energy Reserves 2012 and Supply/Demand Outlook 2013–2022". The ERCB forecast includes only Alberta production. Since oil sands are located in Alberta, the oil sands production forecast can be included in the comparison to other forecasts, as shown in Figure 2.

FIGURE A-2
WESTERN CANADA OIL SANDS PRODUCTION FORECAST



The Base Case forecast has oil sands production increasing by about 2.4 million B/D from 2013 to 2030, to 4.35 million B/D. This is lower than the CAPP 2013 forecast for 2030 production (5.21 million B/D).

The IHS forecast shows an increase in oil sands crude production of about 3.23 million B/D between 2013 and 2037, from 1.95 million B/D to 5.17 million B/D. The annual oil sand production increase over this period is about 134,500 B/D. The NEB 2011 Reference Case forecast[14] calls for an increase in oil sands production of 2.95 million B/D between 2013 and 2035, from 2.15 million B/D to 5.1 million B/D. The annual increase in the NEB forecast is about 134,100 B/D, which is close to the increase in the IHS forecast.

Other forecasts of oil sands growth are available. BP, in its 2013 Energy Outlook, forecasts growth in oil sands production of 2.7 million B/D by 2030.[15] The International Energy Agency ("IEA") forecasts that Canada's oil sands production will grow from 1.6 million B/D in 2012 to 4.3 million B/D by 2035, an increase of 2.7 million B/D.[16] These forecasts are generally comparable (on an annual basis) to the increase in the current IHS forecast.

Conventional Crude Production

Conventional crude production in North America was in decline for many years, but this situation is changing. Figure A-3 shows close agreement on the near term outlook for Western Canada conventional crude production, between the IHS forecast and the CAPP forecast. IHS forecasts an increase of about 200,000 B/D in conventional crude

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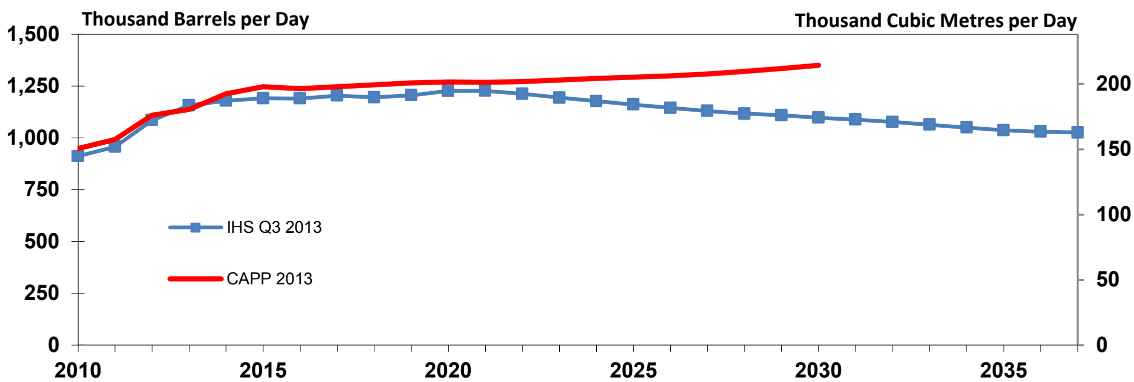
[14] National Energy Board, "Canada's Energy Future: Energy Supply and Demand Projections to 2035", http://www.neb-one.gc.ca/clf-nsi/rnrgynfmtn/nrgyrprt/nrgyftr/2011/nrgsppldmndprjctn2035-eng.pdf, November 2011.

[15] BP Energy Outlook 2030, http://www.bp.com/content/dam/bp/pdf/statistical-review/BP_World_Energy_Outlook_booklet_2013.pdf , accessed on 18 September 2013.

[16] "World needs oil sands crude, IEA economist says", The Globe & Mail, http://www.theglobeandmail.com/report-on-business/industry-news/energy-and-resources/world-needs-oil-sands-crude-iea-economist-says/article5702107/, accessed on 18 September 2013.

production between 2013 and 2020. IHS is calling for a resumption of the decline in conventional crude production after 2015, although the decline rate is offset by growth in pentanes plus supply from tight gas production. CAPP is projecting conventional crude production to remain relatively flat at slightly less than 1.4 million B/D after 2015.

FIGURE A-3
WESTERN CANADA CONVENTIONAL CRUDE PRODUCTION FORECAST



The trend shown in Figure A-3 for conventional crude production in the Base Case forecast is based on expected production from tight shale plays, which depends on the application of advanced production techniques. Such technologies have been applied with success in the Williston Basin in the northern tier of the U.S., and are expected to also be successful in Western Canada.

I-2. NORTH AMERICAN CRUDE SUPPLY/DEMAND BALANCE

The historical and forecast U.S. crude balance is summarized in Table A-1. IHS expects that U.S. refinery crude demand will increase slightly through the end of the decade, and decline thereafter. This crude demand forecast is consistent with IHS' forecast for demand growth of refined products. However, U.S. domestic crude production is forecast to grow for a number of years due to the contribution of tight oil production, before resuming an overall decline. As a result, U.S. crude imports will decline to balance market demand.

U.S. refining capacity in 2013 is approximately 17.7 million B/D, and crude demand is estimated at 15.3 million B/D. In addition to using approximately 7.3 million B/D of domestic crude, U.S. refineries are expected to import an estimated 8 million B/D of crude in 2013, including more than 2.5 million B/D of Canadian crude.

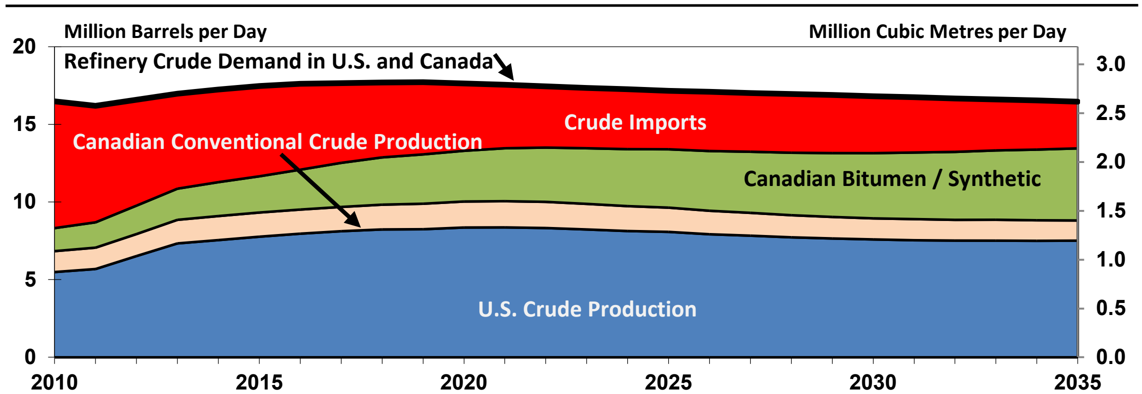
TABLE A-1
TOTAL U.S. CRUDE OIL SUPPLY / DEMAND
(Thousand Barrels per Day)

	2012	2013	2014	2015	2020	2025	2030	2035
Total Runs	15,020	15,264	15,548	15,715	15,860	15,338	14,956	14,574
Total Capacity	17,776	17,689	17,714	17,743	17,743	17,743	17,743	17,743
% Capacity Utilization	84	86	88	89	89	86	84	82
Production	6,521	7,336	7,549	7,768	8,359	8,079	7,593	7,513
Canadian Imports	2,279	2,522	2,690	2,909	3,571	4,270	4,550	5,092
Other Imports	6,133	5,522	5,457	5,263	4,221	3,336	3,109	2,248
Total Imports	8,412	8,043	8,147	8,172	7,793	7,606	7,658	7,340
Total Supply	14,879	15,264	15,548	15,715	15,840	15,338	14,956	14,574

U.S. crude oil production has been declining more or less continuously for two decades. However, production gains from tight oil developments, such as the Williston Basin and Eagle Ford plays, have temporarily reversed this historical decline. As a result, U.S. imports of crude oil are forecast to decrease below 8 million B/D, as shown in Table A-1. U.S. imports of Canadian crude are forecast to increase steadily through 2035, primarily due to U.S. refineries processing growing supplies of oil sands crudes. IHS forecasts that U.S. imports of Canadian crude will reach 3.6 million B/D by 2020, and 5.1 million B/D by 2035.

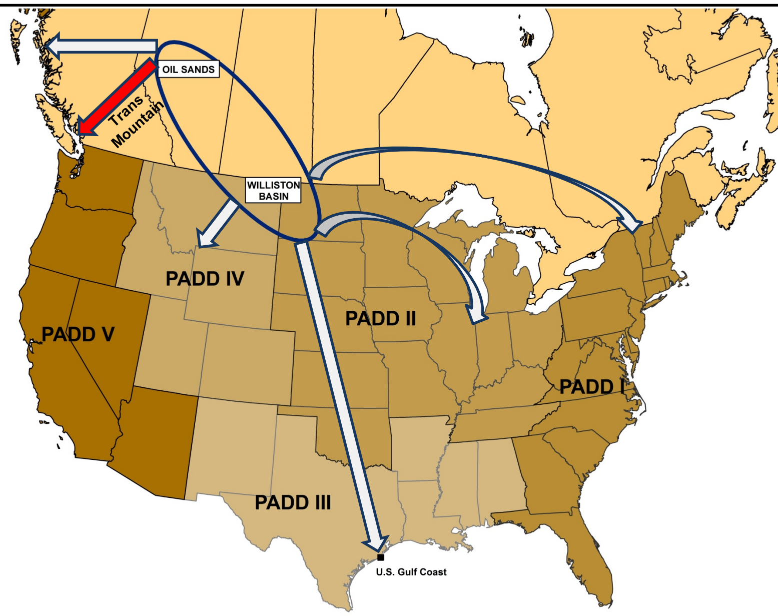
Figure A-4 illustrates the crude supply/demand balance for North America, based on IHS' forecast of crude supply and demand. The growth in Canadian bitumen and synthetic crude runs is expected to offset a decline in domestic U.S. crude production, which is expected to occur early in the next decade. The outlook for crude consumption is relatively flat, which results in a decreased requirement for crude imports from outside of North America over the forecast period.

FIGURE A-4
U.S. AND CANADIAN MARKETS FOR CRUDE OIL



The U.S. is divided into five Petroleum Administration for Defense Districts ("PADD") by the U.S. Department of Energy ("DOE"), as shown in Figure A-5. PADD regions are alternatively referred to in this report as follows: PADD I is the East Coast; PADD II is the Midwest; PADD III is the Gulf Coast; PADD IV is the Rocky Mountains; and PADD V is the West Coast. PADD V includes Alaska and Hawaii.

FIGURE A-5
WESTERN CANADA / NORTHERN U.S. PRODUCTION REGION



Canadian crude currently serves all of the U.S. PADD regions. As infrastructure development continues, and within the constraints of refining capabilities in each region, further growth in market share is expected for Western Canadian crude. The Pacific Northwest region of PADD V is currently served by Trans Mountain. California and other markets in the Pacific Rim also receive Western Canadian crude supplies via Trans Mountain.

For the purposes of this analysis, we have defined a supply region that includes Western Canada and the U.S. northern tier. This supply region is served by some of the same pipelines, and serves many of the same refining locations.

I-3. WESTERN CANADIAN CRUDE SUPPLY

IHS uses the term “marketed supply” to refer to the cumulative volume of all the various crude blends that are delivered by pipeline or rail. Marketed supply is different from production, as it allows for upgrading yield losses and heavy crude diluent blending. Some bitumen and heavy crude may be upgraded at the resource site or at standalone facilities to produce SCO. Depending on the upgrading process employed, SCO can be light or heavy crude. To date most upgrading has converted heavy crude production into light crude supply.

Bitumen and some conventional heavy crude oils require diluent to be shipped by pipeline. The traditional diluent for bitumen is pentanes plus ("C5+"), which is a recovered natural gas liquid. The blended product of bitumen and C5+ is commonly referred to as "DilBit". SCO may also be used as a diluent, in which case the blended product is referred to as "SynBit". The blending of diluent increases the supply of heavy crude and decreases the supply of light crude. The demand for diluent is forecast to increase with growth in bitumen production. The supply of C5+ from traditional sources in Western Canada is expected to grow, due to tight gas developments. Other options are available to supplement the supply of diluent, including import by rail, import or recycle of suitable streams by pipeline,[17] or use of other light crudes.

The Base Case marketed supply forecasts for total crude, heavy crude and light crude are given in Table A-2. The IHS forecast for Western Canada crude supply is compared with the most recent CAPP forecast. Total marketed supply increases in both the Base Case forecast and the CAPP forecast.

TABLE A-2
WESTERN CANADA CRUDE SUPPLY FORECAST COMPARISON
(Thousand Barrels per Day)

	2012	2013	2014	2015	2016	2017	2018	2019	2020	2025	2030	2035	2037
Total Crude Supply													
IHS Q3 2013	3,193	3,462	3,713	3,964	4,285	4,581	4,803	4,985	5,105	5,862	6,610	7,348	7,675
CAPP 2013	3,199	3,438	3,738	3,935	4,130	4,333	4,564	4,804	5,165	6,773	7,846		
Heavy Crude Supply													
IHS Q3 2013	1,791	2,004	2,230	2,453	2,746	2,991	3,193	3,372	3,485	4,323	5,153	5,985	6,306
CAPP 2013	1,747	1,872	2,100	2,267	2,498	2,722	2,965	3,205	3,561	5,120	6,093		
Light Crude Supply													
IHS Q3 2013	1,402	1,458	1,482	1,511	1,539	1,590	1,610	1,612	1,620	1,538	1,458	1,440	1,369
CAPP 2013	1,452	1,566	1,637	1,668	1,632	1,610	1,600	1,598	1,604	1,653	1,752		

The refining regions served by Western Canadian crude supply may also be served by U.S. northern tier crude supply. The pipelines serving markets in the Upper Midwest and Midwest region, as well as Ontario, provide access to Western Canadian and U.S. northern tier crude supply. U.S. northern tier crude supply may be considered competitive with Western Canadian crude supply, both from a logistics perspective and from a crude quality perspective. The crude oils available in the U.S. northern tier are generally light sweet grades that could be processed by a wide range of refineries. However, crude supplies in the U.S. northern tier cannot access market regions to the west of Edmonton, including the Pacific Northwest, California and Asian markets. Trans Mountain serves these markets.

[17] The Enbridge Southern Lights Pipeline Project was constructed to provide access to imported or recycled sources of suitable diluent streams. It commenced operations in 2010. The Cochin Pipeline is proposed for reversal and conversion from natural gas liquids ("NGL") export service to condensate import service. If approved, it would commence operations in 2014.

II. NORTH AMERICAN CRUDE OIL MARKET OVERVIEW

Following is an overview of selected regional refining industries in North America. The key features of the regional industries are refining capacity and configuration. Refinery capacity is normally designated by atmospheric crude distillation capacity. Configuration refers to the conversion capabilities of the refining industry, with the usual designations (from most complex to least complex) being coking (also called full conversion), cracking (medium conversion), hydroskimming and topping.

In major North American markets, IHS considers the marginal (or breakeven) refinery configuration to be the cracking configuration. This configuration includes either a fluid catalytic cracking ("FCC") or hydrocracking unit for conversion of vacuum gas oil ("VGO") to lighter fuel products.

II-1. WESTERN CANADA / ONTARIO

There are eight refineries in Western Canada with total crude distillation capacity of 655,000 B/D, as shown in Table A-3. Capacity information shown for refineries in this report is based on the 2012 Oil & Gas Journal Refining Survey[18], and IHS estimates. About 40 percent of Western Canada capacity is in coking refineries, and 54 percent is in cracking refineries. Western Canadian refineries rely exclusively on regional crude supplies, as they have access to crude supplies before they enter major trunk pipelines. The Chevron Canada Limited refinery at Burnaby, BC receives crude from Trans Mountain.

The Ontario refining industry is comprised of 5 refineries with total crude distillation capacity of about 469,000 B/D. Four of the refineries are located in or near Sarnia, ON. Most of the Ontario refining capacity is in cracking configurations. The Ontario refineries process a range of Western Canadian crudes that they receive via the Enbridge system.

TABLE A-3
WESTERN CANADA/ONTARIO REFINERY CONFIGURATION: JANUARY 2013

	Western Canada			Ontario			Total		
		Capacity			Capacity			Capacity	
	Number	MB/D	Percent	Number	MB/D	Percent	Number	MB/D	Percent
Coking	2	265	40	1	121	26	3	386	34
Cracking	4	353	54	3	268	57	7	622	55
Hydroskimming	1	25	4	-	-	-	1	25	2
Topping	1	12	2	1	80	17	2	92	8
Total	8	655	100	5	469	100	13	1,125	100

Source: Oil & Gas Journal (December 2012) and IHS estimates

[18] Oil & Gas Journal, "2012 Worldwide Refining Survey", December 3, 2012. The Oil & Gas Journal survey has been used as a consistent source for refinery capacity information throughout this document, although it recognized that company information and other sources may be available. Where capacity information is not available from the Oil & Gas Journal survey, other sources (including IHS estimates) have been utilized.

II-2. U.S. MIDWEST (PADD II)

The U.S. Midwest (PADD II) covers the heartland of the United States. Within this large region, there are a total of 26 refineries with total crude distillation capacity of 3.81 million B/D. Table A-4 summarizes refineries in PADD II by type. Approximately three-quarters of PADD II refining capacity is accounted for in coking configurations.

TABLE A-4
PADD II REFINERY CONFIGURATION: JANUARY 2013

		CAPACITY	
	Number	**MB/D**	**Percent**
Coking	14	2,782	73
Cracking	10	1,008	26
Hydroskimming	2	20	1
Topping	-	-	-
Total	26	3,810	100

Source: Oil & Gas Journal (December 2012) and IHS estimates

IHS adopts the regional divisions used by the Energy Information Administration ("EIA") for PADD II. The refining sub-districts in PADD II include the Upper Midwest (refineries in Minnesota, North Dakota and Wisconsin), the Mid-continent (refineries in Kansas and Oklahoma) and the Midwest (refineries in Kentucky, Illinois, Indiana, Michigan, Ohio and Tennessee).

The Upper Midwest and northern portion of the Midwest (in the states bordering the Great Lakes) have traditionally been key markets for Western Canadian crude. Refineries in the southern Midwest (around Wood River, IL) and the Mid-continent have been increasing their consumption of Canadian crudes. Several pipeline projects (discussed later) have allowed Canadian crudes to gain access to these markets, as refiners sought new supplies to replace declining domestic production.

II-3. U.S. ROCKY MOUNTAIN REGION (PADD IV)

The U.S. Rocky Mountain region (PADD IV) has a small refining industry, with 16 refineries and total crude distillation capacity of 622,000 B/D. Table A-5 summarizes capacity and configuration data for the PADD IV refining industry. Coking (55 percent) and cracking (42 percent) account for the majority of the regional refining capacity.

TABLE A-5
PADD IV REFINERY CONFIGURATION: JANUARY 2013

		CAPACITY	
	Number	**MB/D**	**Percent**
Coking	6	341	55
Cracking	7	264	42
Hydroskimming	3	17	3
Topping	-	-	-
Total	16	622	100

Source: Oil & Gas Journal (December 2012) and IHS estimates

Historically, crude production in PADD IV was surplus to the needs of the regional refineries. Refineries in northern PADD IV (Montana) access Canadian crude through southbound regional pipelines originating in Alberta. Refineries in the southern PADD IV markets of Salt Lake City, UT and Denver, CO process indigenous and imported Canadian crude, mainly light sweet and synthetic grades. In recent years, production of light sweet crude from shale formations such as the Bakken play has added a new source of supply for PADD IV.

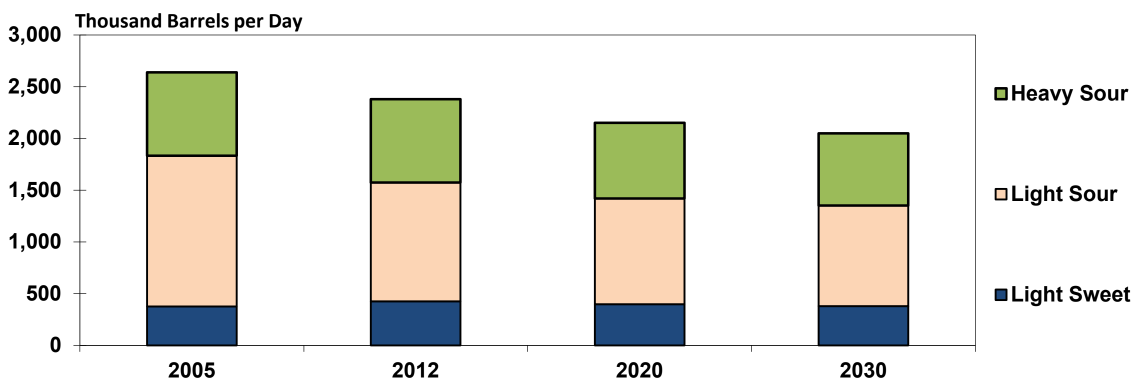
II-4. U.S. WEST COAST (PADD V)

The U.S. West Coast (PADD V) includes refineries in California, Washington State, Alaska and Hawaii. The major refining industries on the West Coast are centred in Los Angeles, San Francisco, and the Pacific Northwest. Smaller refining centres are located in Hawaii and in Alaska. The California refining industry includes large, complex refineries that are located in proximity to major refined product markets. California is a small but growing market for Western Canadian crude.

Since the late 1990s, PADD V has become increasingly dependent on crude imports and refined product transfers from other PADD regions to satisfy its product demand. This trend towards greater integration of the PADD market with other markets, both in the U.S. and internationally, is expected to continue in the future.

Figure A-6 summarizes the historical and future outlook for crude demand by type in PADD V. Overall demand for crude is forecast to decrease, largely due to mandated fleet efficiency improvements which will reduce gasoline demand. However, runs of light sweet and heavy sour crude are forecast to remain relatively stable in PADD V. Descriptions for the regional refining industries in the Pacific Northwest and California, including discussion of the types and sources of crude processed, and the potential for oil sands crudes, are presented below the figure.

FIGURE A-6
CRUDE SLATE FOR PADD V



Pacific Northwest

The Pacific Northwest refining industry consists of five refineries, all located in Washington State. Table A-6 summarizes capacity and configuration information for the Washington State refineries. There are four fuels refineries in Puget Sound and a smaller asphalt plant in Tacoma, with a total combined distillation capacity of 630,900 B/D. Two of the Puget Sound refineries are coking configurations (BP and Shell) and two are cracking configurations (Tesoro and Phillips 66).

TABLE A-6
REFINERIES IN WASHINGTON STATE

Owner	Location	Configuration	Crude Capacity (B/D)
BP	Ferndale	Coking	222,300
Phillips 66	Ferndale	Cracking	101,000
Shell Oil Products US	Anacortes	Coking	148,600
Tesoro West Coast Co.	Anacortes	Cracking	120,000
US Oil & Refining Co.	Tacoma	Hydroskimming	39,000
Total			630,900

Source: Oil & Gas Journal (December 2012)

Historically, Alaskan North Slope ("ANS") has been the dominant crude processed in Washington State, with the balance coming from imports. Canada, Latin America, Africa and the Middle East are the main sources of imported crude for the Washington State refineries. Imports of Western Canadian crude in the Pacific Northwest region are received via the Trans Mountain system, and include a range of light and heavy crudes. In 2012, refineries in Washington State imported approximately 146,000 B/D of Canadian crude.

California

The California refining industry is among the most complex regional refining industries in the world, and features extensive heavy oil upgrading capability. Many refineries were originally developed to process heavy California crude oils, but as the use of fuel oil was phased out of the utility sector, refineries added coking capacity in order to eliminate fuel oil sales. As shown in Table A-7, there are 18 California refineries with approximately 2.0 million B/D of crude oil distillation capacity, most of which is in coking configurations. Two refineries owned by Alon, with capacity of 83,000 B/D, are temporarily shutdown. They are included in Table A-7, because they are expected to restart.

TABLE A-7
CALIFORNIA REFINERY CONFIGURATION: JANUARY 2013

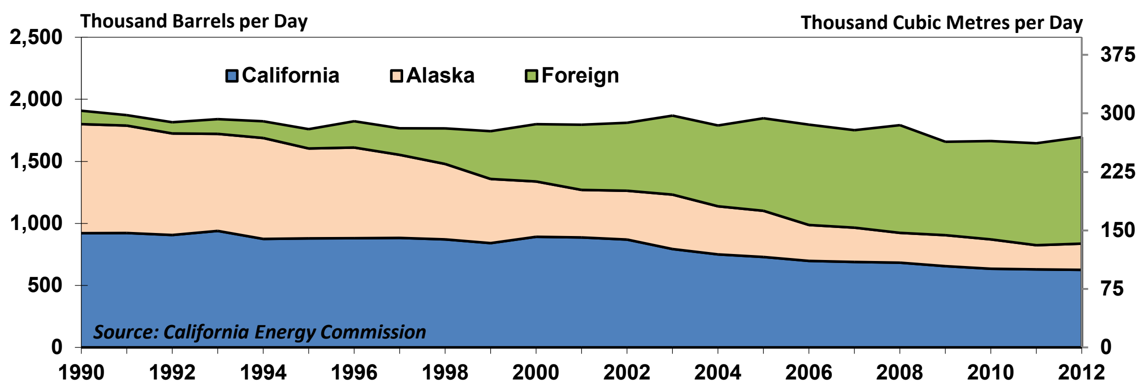
		CAPACITY	
	Number	MB/D	Percent
Coking	10	1,588	80
Cracking	1	243	12
Hydroskimming	2	76	4
Topping	5	82	4
Total	18	1,989	100

Source: Oil & Gas Journal (December 2012) and IHS estimates

ANS and California crude account for slightly more than half of the crude runs in California. According to the California Energy Commission,[19] the proportion of domestic crude runs has steadily decreased, from about three-quarters of the state total in 2000 to less than half in 2012. In 2012, about 837,000 B/D of domestic crude was run in the state. Of this volume, about 625,000 B/D was California production, and 211,000 B/D was from Alaska. The remaining deficit, approximately 860,000 B/D, was satisfied through imports of foreign crude. Figure A-7 summarizes the historical crude supply for California, and shows the increasing dependence on imported crude.

[19] California Energy Commission, http://energyalmanac.ca.gov/petroleum/statistics/2010_foreign_crude_sources.html, accessed August 15, 2013

FIGURE A-7
CALIFORNIA CRUDE SUPPLY SOURCES



The main source of imports for California refineries has been the Middle East, which has accounted for up to 50 percent of total imports in recent years. Saudi Arabia and Iraq have been the leading suppliers of crude to California refineries. U.S. EIA import statistics indicate that Middle Eastern crudes are mainly light sour grades, which are suitable for processing in many California refineries. Light sour and heavy sour crudes are also imported from Latin America.

Imports of Canadian crude by California refineries have been a relatively small fraction of the total imports to the state, but the trend has been increasing. California Energy Commission statistics[20] indicate that Canadian crude imports in 2012 were 39,000 B/D (about 2.3 percent of total California crude runs). This is up from 15,000 B/D in 2007, which was about 0.8 percent of California crude runs in that year.

Potential for Oil Sands Crudes

There are several factors that favour growth in oil sands crude in the PADD V market. Western Canadian crude has a logistical advantage compared to other supply sources for the PADD V refineries, and in particular for the Pacific Northwest refineries. The Pacific Northwest refineries have capabilities to process a range of oil sands light and heavy crudes, in addition to conventional crudes.

The size and complexity of the refining industry in California, and the trend of growing dependence on imports in the state, suggests that interest in access to Western Canadian supply should continue to increase. IHS expects bitumen and conventional heavy blends from Western Canada to be of the most interest to California refineries. The existing capabilities of the California refining industry to process heavy crude oil should allow Western Canadian heavy crudes to gain market share, particularly as domestic supplies of heavy crude continue to decline. Constraints for Western Canadian heavy crude processing would need to be addressed on a refinery-specific basis, given

[20] California Energy Commission, ibid.

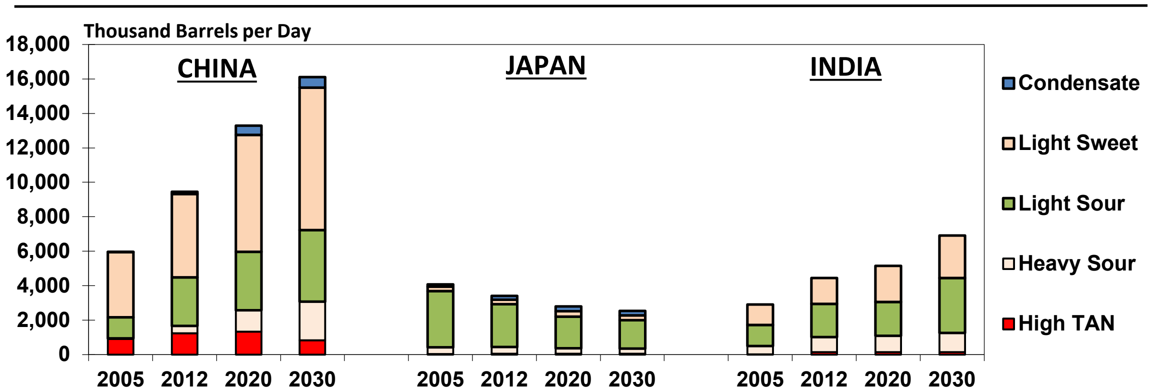
that bitumen blends have different characteristics than the indigenous heavy crudes historically processed in California. Such an analysis is beyond the scope of this report.

III. ASIAN CRUDE OIL MARKET OVERVIEW

There are large refining markets in Asia that can process Western Canadian crude. For this report, IHS has provided a brief description of selected Asian countries that are markets of growing interest for Western Canadian producers. The focus is on refining industries in China, Japan and India. Several other Asian countries are also discussed, but in less detail.

Figure A-8 summarizes the historical and future outlook for crude demand by type in the aforementioned Asian countries. Demand for most types of crude is forecast to increase in China and India, as refining industries in these countries expand and evolve to meet domestic product requirements. Descriptions for the refining industry in each of these countries, the types and sources of crude processed, and the potential for oil sands crudes, are presented below the figure.

FIGURE A-8
CRUDE SLATE FOR SELECTED ASIAN COUNTRIES



III-1. CHINA

Crude distillation capacity in China is the largest among all countries in Asia. Capacity has been growing rapidly. Strong product demand growth has prompted increases in refining capacity, and has also increased the operating rate of existing refineries. Increasing product imports to China have also been reported. Capacity expansions will continue into the foreseeable future.

Table A-8 summarizes the distillation capacity and configuration for the Chinese refining industry.[21] More than three-quarters of the 9.8 million B/D of distillation capacity is in

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[21] Oil & Gas Journal, "2012 Worldwide Refining Survey", December 3, 2012, and IHS estimates.

coking refining configurations, although these refineries are oriented to processing indigenous crudes. Simple refining capacity accounts for a small fraction of total capacity, excluding small regional refineries. Much of this capacity is located in inland regions, or in small state-owned refineries that produce feedstocks for petrochemical plants.

TABLE A-8
CHINA REFINERY CONFIGURATION: JANUARY 2013

	Crude Distillation Capacity		
	Number	**MB/D**	**Percent**
Coking	42	7,405	76
Cracking	22	2,082	21
Hydroskimming	1	82	1
Topping	3	205	2
Total	68	9,774	100

Note: Excludes distillation capacity of local refineries.
Source: Oil & Gas Journal (December 2012) and IHS estimates

IHS expects that domestic refining will continue to supply the majority of Chinese fuel requirements over the forecast period. Several new refineries are currently under construction, and these, along with further expansions and upgrades at existing refineries, are expected to keep pace with projected demands at least through the end of this decade.

Most of the refineries in China were originally designed to process indigenous Chinese crudes, but now that runs far exceed domestic production most of the coastal refineries are equipped to process Middle East and other imported crude. China now imports about half of its crude slate. The Middle East and Africa together account for most of China’s crude imports.

Potential for Oil Sands Crudes

IHS expects diversification of China’s crude sources and crude slate, to include more sour and heavy crudes. An increasing need for imported crude of all types suggests that interest in Canadian oil sands crudes should continue. China is generally expected to move towards more complex refining configurations as capacity is added, with the addition of cracking, coking and hydroprocessing capacity.

Light sweet SCO could be processed in coastal refineries in China that have sweet crude cracking capacity, given its characteristic low sulphur and high distillate yield. China is expected to increase its imports of light sweet crude by 2020, to help supply the growth in refinery runs. IHS believes that SCO demand potential could grow with this requirement.

The amount of Canadian bitumen blends that may be processed in existing refineries in China depends on their ability to handle high sulphur residue in coking units, and on the availability of hydrotreating capacity to handle hydrogen deficient bitumen-derived crudes. However, the potential for lower quality crude production from Western Canada to be integrated with new build refinery capacity in dedicated projects is significant. Interest by Chinese firms in Canadian oil sands is indicated by the recent CNOOC acquisition of Nexen[22] and by the positions taken in other oil sands companies. These ventures are expected to support the expansion of domestic refining capacity in China.

III-2. JAPAN

The Japanese refining industry (summarized in Table A-9) consists of 31 refineries, with total distillation capacity of 4.18 million B/D.[23] Japan continues to downsize and consolidate its refining industry.

TABLE A-9
JAPAN REFINERY CONFIGURATION: JANUARY 2013

	Crude Distillation Capacity		
	Number	**MB/D**	**Percent**
Coking	4	357	9
Cracking	22	3,593	86
Hydroskimming	2	155	4
Topping	3	73	2
Total	31	4,178	100

Source: Oil & Gas Journal (December 2012) and IHS estimates

The Japanese refining industry is well balanced, and has historically been oriented toward meeting domestic refined product demand. However, Japan's petroleum consumption is forecast to decline slowly, as shown in Figure A-8. With the decline of domestic markets, Japanese refiners may seek opportunities to export products, potentially allowing them to serve other Asian markets.

Japanese crude imports are heavily dominated by Middle East sour grades, which accounted for almost all imports in 2012. Sweet crude imports are low, currently less than 10 percent of total crude imports. African crudes comprise a small fraction of total Japanese crude runs.

[22] The Globe & Mail, "CNOOC completes $15.1-billion takeover of Nexen", http://www.theglobeandmail.com/report-on-business/industry-news/energy-and-resources/cnooc-completes-151-billion-takeover-of-nexen/article9043968/, February 25, 2013, accessed on October 3, 2013.

[23] Oil & Gas Journal, "2012 Worldwide Refining Survey", December 3, 2012, and IHS estimates.

Potential for Oil Sands Crudes

Our analysis of oil sands market potential in Japan suggests that light sweet SCO could be used at many Japanese refineries in place of imported sweet or light sour crude. IHS believes that SCO substitution could be limited by operating constraints for Japanese refineries. However, alternative grades of SCO may be developed, which would conform to the constraints of the Japanese refining industry. Alternatively, bitumen blends with SCO (normally referred to as SynBit) or other blends of oil sands and conventional crudes may be of interest to Japanese refineries. Cracking refineries that process light sour crude oil could also directly substitute light sweet SCO, if justified by substitution economics.

III-3. INDIA

The capacity and configuration of the Indian refining industry is summarized in Table A-10. As of January 2013, India has total installed distillation capacity of 4.43 million B/D in 21 refineries, and a high concentration of conversion capacity.[24] A number of refinery expansions and grassroots projects are at various stages of development.

TABLE A-10
INDIA REFINERY CONFIGURATION: JANUARY 2013

	Crude Distillation Capacity		
	Number	**MB/D**	**Percent**
Coking	12	2,749	52
Cracking	8	1,656	47
Hydroskimming	0	-	0
Topping	1	20	0
Total	21	4,425	100

Source: Oil & Gas Journal (December 2012) and IHS estimates

The crude oil processed by India's refining industry is a mixture of indigenous production and imports from the Middle East, Southeast Asia and Africa. Crude oil imports have increased over the last few years, a reflection of stagnant crude oil production and strong demand growth. The crude oil slate is increasingly composed of light to medium gravity sour crudes, in contrast to the domestic production, which is mainly light sweet. Most recently installed capacity and current projects are designed for sour Middle East crude or heavy Atlantic Basin crude.

[24] Oil & Gas Journal, “2012 Worldwide Refining Survey”, December 3, 2012, and IHS estimates.

Potential for Oil Sands Crudes

As noted above, Indian refineries currently process a mainly light crude slate. Light sweet SCO may be a substitute for African sweet imports currently processed in India. IHS believes these opportunities are likely to be limited due to logistical disadvantages.

Although limited volumes of heavy crude have historically been processed in Indian refineries, this trend is changing. Several Indian refineries require heavy feedstock, in particular the Reliance refinery complex at Jamnagar. The Reliance refinery consists of two facilities with total distillation capacity of 1.24 million B/D.[25] The second Reliance refinery, with capacity of 580,000 B/D, was started up in 2009. Due to its proximity to the Middle East, Reliance would see a logistical advantage to process Middle East heavy crude rather than Western Canadian crude. Nevertheless, interest by Indian refineries in Western Canadian heavy crude is growing. IHS attributes this to competing demand for heavy crude in the Middle East from new or modified refineries, and to an interest by Indian refiners in securing alternative sources of supply.

III-4. OTHER ASIAN COUNTRIES

South Korea has a large domestic refining industry, with combined distillation capacity of about 3 million B/D. There is no crude production in South Korea, so all crude runs are based on imported supplies. Imported crudes are sourced from a variety of suppliers, and the Middle East is the largest supply region. The crude slate is relatively light. IHS estimates that South Korean refineries could substitute light sweet SCO from Western Canada for other light crude imports. Alternative formulations of SCO, which are closer in quality to Middle East sour crudes, would likely be of interest in South Korea.

There are three large fuels refineries and one condensate splitter in Singapore, with combined distillation capacity of 1.35 million B/D. There is no crude production in Singapore, so all crude runs are imported. Singapore refineries rely mainly on Middle East sour crude, and to a lesser extent on Asian sweet crude. Markets for Canadian oil sands crudes in Singapore could include substitution of sweet SCO for other light crudes.

There are three large refining centres in Taiwan, with combined distillation capacity of about 1.3 million B/D. Because Taiwan has almost no crude production, runs are dominated by imports. Middle East sour crude is the dominant crude type processed in Taiwan. IHS sees oil sands crude potential in Taiwan as somewhat limited, but sweet SCO could certainly be substituted for other imported light sweet crudes.

[25] Oil & Gas Journal, "2012 Worldwide Refining Survey", December 3, 2012.

IV. CANADIAN CRUDE OIL EXPORT PIPELINE CAPACITY & UTILIZATION

Canadian crude oil export pipeline systems are described in this section. Current capabilities and expansion plans for the major export pipeline systems are presented. The utilization of pipeline systems is discussed, with reference to the crude supply forecast provided in the previous section of this report. Table A-11 summarizes the major pipeline projects that would increase markets for Western Canadian crude oil.

IV-1. TRANS MOUNTAIN

Trans Mountain transports crude oil, as well as various feedstocks and blendstocks from Edmonton and Kamloops, BC to its Burnaby terminal (for the Chevron Burnaby refinery), to its Westridge Marine Terminal dock (for marine exports), and also to its U.S. affiliate, Trans Mountain Pipeline (Puget Sound) LLC ("Puget Sound Pipeline") (for export from Sumas, BC to four Washington State refineries). Trans Mountain delivers various grades of light and heavy crudes. Trans Mountain also transports refined products from Edmonton to both Kamloops and Burnaby.

Trans Mountain capacity is dependent upon the amount of heavy crude being shipped. The convention has been to define capacity based on 20 percent of the crude oil shipped as heavy oil. On this basis, the current operational capacity is 300,000 B/D.

Trans Mountain has completed a number of expansion projects. The system reached its current capacity in 2008 with the completion of its Anchor Loop project, which added 40,000 B/D of capacity. Application is being made for the proposed Trans Mountain Expansion Project ("TMEP"). Subject to the outcome of the NEB hearing process, Trans Mountain plans to begin construction in 2016. The project would go into service in late 2017.

TABLE A-11
MAJOR PIPELINE PROJECTS CONNECTING OIL SANDS TO FUTURE MARKETS

Destination	Pipeline project (proponent)	Route	Distance (km)	Capacity (B/D)	Status	Proposed in-service date
US Gulf Coast	Flanagan South (Enbridge)	Flanagan, IL to Cushing, OK	960	585,000	Announced	2014
US Gulf Coast	Keystone XL (TransCanada Pipelines)	Hardisty, AB to Port Arthur, TX	2,750 [1]	830,000	Regulatory review	2015
US Gulf Coast	Seaway reversal—Phase 1 (Enbridge/Enterprise Products)	Cushing, OK to Freeport, TX	800	150,000	Operating	2012
US Gulf Coast	Seaway—Phase 2 (Enbridge/Enterprise Products)	Cushing, OK to Freeport, TX	800	250,000	Operating	2013
US Gulf Coast	Seaway—Phase 3 (Enbridge/Enterprise Products)	Cushing, OK to Freeport, TX	800	450,000	Application	2014
East Coast	Energy East (TransCanada Pipelines)	Alberta to Montreal and/or Quebec City, QC and/or Saint John, NB	3,500	1,100,000	Announced	2017
East Coast	Line 9 Re-reversal (Line 9B) (Enbridge)	Sarnia, ON to Montreal, QC [2]	640	300,000	Regulatory review	2014
East Coast	Portland to Montreal Pipeline Reversal (Montreal Pipe Line)	Montreal, QC to South Portland, ME	380	140,000	Conceptual	n/a
West Coast	Northern Gateway Pipelines (Enbridge)	Bruderheim, AB to Kitimat, BC	1,180	525,000	Regulatory review	2018
West Coast	Trans Mountain Expansion Project (Kinder Morgan)	Edmonton, AB to Westridge Marine Terminal in Burnaby, BC	1,150	590,000	Regulatory review	2017

Source: Various sources and IHS analysis

Notes: (1) Keystone XL consists of two parts. A 1,897-km (1,179-mi) leg from Hardisty, Alberta to Steele City, Nebraska, and a 780-km (485-mi) leg from Cushing, Oklahoma to Nederland, Texas combined with a 76-km (47-mi) lateral to the Houston, Texas area (called the Gulf Coast Pipeline Project).

(2) In July 2012 the National Energy Board of Canada approved the reversal of the 192-km section of Line 9 from Sarnia, ON to North Westover, ON ("Line 9A"). The reversal of the line from Montreal, QC to North Westover ("Line 9B") and an increase in capacity of the system are proposed.

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IV-2. ENBRIDGE MAINLINE

The majority of Canadian crude produced in Alberta currently flows east through the Enbridge Pipeline System (the portion in Canada) and the Enbridge Energy Partners, L.P. System (the connecting Lakehead system portion in the U.S.). Together these two systems have the ability to supply crude directly and indirectly to numerous refineries in Canada and the U.S. The system receives other crudes along the route in both Canada and the U.S.

Enbridge has continued to expand the mainline system with approval of the NEB and with agreement from crude oil producers, as represented by CAPP. Recently completed and potential Enbridge export expansion projects are summarized below:

- **Alberta Clipper (Line 67) Expansion:** Enbridge is expanding the capacity of its Line 67 (initially the Alberta Clipper Pipeline) in phases, from 450,000 B/D to 800,000 B/D.

- **Flanagan South Pipeline:** Enbridge is proposing the Flanagan South Pipeline Project, a 36-inch diameter pipeline that would originate in Flanagan, IL and terminate in Cushing, OK. The majority of the pipeline would parallel the existing Enbridge Spearhead pipeline right-of-way. Initial capacity of the Flanagan South Pipeline would be 585,000 B/D. Construction would proceed from mid-2013 to mid-2014, and the line would be in-service by mid-2014.

- **Line 9 Reversal:** Line 9 is an existing Enbridge pipeline with capacity of 240,000 B/D that extends from Montreal, QC to Sarnia, ON and currently transports offshore crude oil in a westbound direction. Enbridge has NEB approval to reverse a section of Line 9 between Sarnia and North Westover, ON, and is also proposing the Line 9B Reversal and Line 9 Capacity Expansion Project, which would reverse the pipeline between North Westover and Montreal to allow Western Canadian crude to supply refineries in Quebec.

IV-3. ENBRIDGE NORTHERN GATEWAY

The proposed Enbridge Northern Gateway Project would consist of twin pipelines from Edmonton to a new marine terminal at Kitimat on the West Coast of British Columbia. An export pipeline would have capacity of 525,000 B/D, and an optional diluent import pipeline would have capacity of 193,000 B/D. Wharfage and terminal facilities at Kitimat would be designed to handle Very Large Crude Carrier (“VLCC”) tankers for Canadian crude exports, and up to Suezmax class tankers for condensate imports.

A regulatory application was filed by Enbridge in mid-2010. An independent review process is being led by the NEB and the Canadian Environmental Assessment Agency (“CEAA”). The Northern Gateway hearing process has been completed. The Joint Review Panel (“JRP”) assigned to review the project is scheduled to submit its report to the federal government by December 31, 2013. The pipeline is proposed to start up in 2018.[26]

IV-4. KEYSTONE

The Keystone pipeline project was developed by TransCanada, and put into service in 2010. The project allows Canadian crude to reach Wood River, IL and Patoka, IL. In July 2008, the NEB approved Keystone's application for an expansion of the Phase 1 Keystone system to reach Cushing, OK. The extension of the Keystone system south to Cushing, OK from Steele City, NE and expansion to 590,000 B/D of capacity was started up in 2011.

Keystone XL

TransCanada proposed the Keystone XL Pipeline ("KXL") in 2008, with a route that would transport crude from Hardisty, AB to Texas via Cushing to potentially serve refineries on the Gulf of Mexico. The project requires a Presidential Permit, which would be issued by the U.S. Department of State. A decision on the KXL project has been deferred until late 2013 or early 2014. KXL would have a capacity of 700,000 B/D from Hardisty, AB to Cushing, and 500,000 B/D from Cushing to the Gulf Coast. It would carry heavy and light Canadian crudes. The proposed in-service date for KXL is 2015, although given the delay in the state department decision the project has been delayed until 2016 in our balances.

IV-5. ENERGY EAST

The TransCanada Energy East Pipeline is a proposed 4,500-kilometer pipeline that would have capacity to transport 1.1 million B/D from Alberta, Saskatchewan and the U.S. northern tier to refineries in Eastern Canada and beyond. The project involves: conversion of an existing natural gas pipeline to an oil transportation pipeline; construction of new pipeline connections in Alberta, Saskatchewan, Manitoba, Eastern Ontario, Quebec and New Brunswick to link up with the converted pipe, and construction of the associated facilities required to ship crude oil from Alberta to Quebec and New Brunswick, including marine facilities that enable access to other markets by ship. The planned starting point for Energy East would be a new tank terminal in Hardisty, AB. New terminals would be built in Saskatchewan, in the Quebec City area and in the Saint John, NB area. The pipeline would deliver oil to existing refineries in Montreal, Quebec City and Saint John. Crude oil could then be exported to Atlantic Basin markets from either Quebec or Saint John. The project is currently estimated to cost $12 billion.

[26] "Northern Gateway pipeline to be running by 2018, says Enbridge", http://www.cbc.ca/news/canada/british-columbia/northern-gateway-pipeline-to-be-running-by-2018-says-enbridge-1.1875899, October 2, 2013, accessed on October 3, 2013.

Submission of regulatory applications to the NEB for approval to build and operate the Energy East Pipeline is planned for early 2014. Assuming approval by late 2015, the project is expected to be in service to Montreal and Quebec City in late 2017 and to Saint John in late 2018.

IV-6. OTHER EXPORT PIPELINES

The Express Pipeline system ("Express") is owned by Spectra Energy, who acquired it in 2013. Express was expanded in 2005 to its current capacity of about 280,000 B/D. Express is comprised of the Express Pipeline (from Hardisty, AB to Casper, WY) and the Platte Pipe Line Company ("Platte") (from Casper, WY to Wood River, IL).

The Enbridge North Dakota Pipeline gathers North Dakota and Montana crudes for shipment east to Clearbrook, MN where it joins the main line of the Lakehead system. Due to increased crude production in Montana and North Dakota and oversupply in the U.S. Rocky Mountain region, movements on the Enbridge North Dakota Pipeline have increased and exports of Canadian crudes, especially Midale, on this system have fallen. The Enbridge Bakken Program is a coordinated set of projects in Canada and the U.S., which would accommodate growth in regional crude production.

The Wascana Pipeline (owned by Plains Midstream) runs from Regina to the Montana border, where it connects to the Bridger Pipeline. Bridger moves crude south to the U.S. Rocky Mountain market. The Wascana Pipeline has a nominal capacity of around 50,000 B/D. Although it has not operated in recent years, Plains plans to reverse the Wascana pipeline to Regina and tie-in Bakken production.

Other crude oil pipelines that export crude from Alberta to pipelines in the U.S. include the Rangeland Pipeline (capacity of about 65,000 B/D) and the Milk River Pipeline (118,000 B/D).

IV-7. RAIL CAPACITY

Extraordinary discounts for Western Canadian crudes have encouraged the use of rail loading operations to ship crude to market. Rail movements of crude oil from Western Canada have increased from negligible levels in 2011 to an estimated 145,000 B/D in the second quarter of 2013. IHS expects rail movements to be sensitive to crude price discounts.

Rapid growth is projected in Western Canadian and U.S. northern tier crude on-loading capacity, as summarized in Table A-12. More project announcements are expected. New rail loading capacity is expected to incorporate efficiency improvements, which will involve the use of unit trains or other efficiency improvements in many cases.[27] This will contribute to improved economics, particularly for facilities that are connected by pipeline.

TABLE A-12
RAIL LOADING FACILITIES IN WESTERN CANADA AND NORTH DAKOTA

Company	Location	Rail Company	Capacity, MB/D Current	Additions (1)	Total
Western Canada					
TORQ	Kerrobert, SK	CP	-	168	168
USD/Gibson	Hardisty, AB	CP	-	140	140
TORQ	Unity, SK	CN/CP	11	59	70
Canexus	Bruderheim, AB	CN/CP	30	40	70
Gibson Energy	Edmonton. AB	CN/CP	-	60	60
Altex Energy	Lashburn, SK	CN	30	30	60
Kinder Morgan	Edmonton. AB	CN/CP	-	40	40
Enbridge/Keyera	Cheecham, AB	CN	32	-	32
TORQ/Altex	Lloydminster, SK	CP	27	-	27
TORQ	Whitecourt, AB	CN	12	12	24
Other	Various		55	58	113
Total Western Canada Capacity			197	607	804
North Dakota					
Inergy	Epping	BNSF	120	-	120
Bakken Oil Express	Dickenson	BNSF	100	-	100
Savage Services	Trenton	BNSF	90	-	90
Enbridge	Berthold	BNSF	80	-	80
Dakota Plains	New Town	CP	30	50	80
Plains	Ross/Manitou	BNSF	65	-	65
EOG	Stanley	BNSF	65	-	65
Plains	New Town	CP	65	-	65
Hess	Tioga	BNSF	60	-	60
Musket	Dore	BNSF	60	-	60
Great Northern	Fryburg	BNSF	60	-	60
Other	Various	BNSF	70	-	70
Total North Dakota Capacity			935	50	985

Note: (1) Additions up to the end of 2016

In IHS' opinion, proposed pipelines will add sufficient takeaway capacity for crude oil from Western Canada and the U.S northern tier to reduce the need for rail loading. As such, rail loading capacity for crude oil would become underutilized by 2015 or 2016.

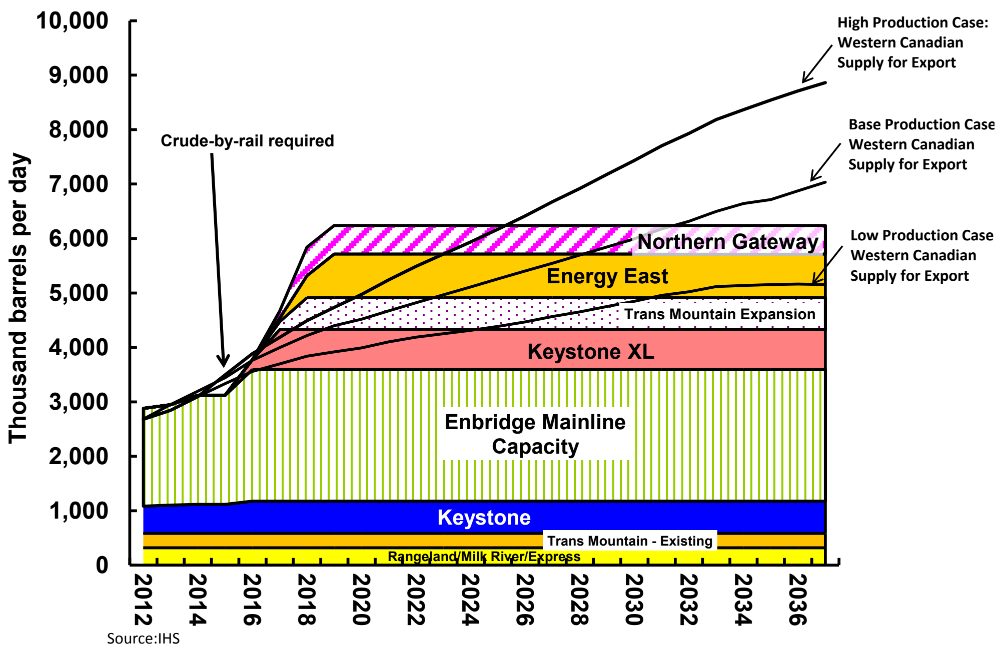
[27] Shipment of different bitumen blends by rail may contribute to more efficient operation. Rather than ship traditional blends of bitumen and condensate which meet pipeline specifications, blends with lesser volumes of added condensate or no added condensate may be prepared. The costs of rail transportation include loading and unloading charges, transportation charges and tank car lease costs.

However, if new pipelines lag oil sands growth, we expect that rail will be available to fill the gap. This is consistent with the response observed over the last two years.

IV-8. WESTERN CANADA TAKEAWAY CAPACITY VS. PRODUCTION

The forecast of crude oil supply for export from Western Canada is compared with pipeline takeaway capacity in Figure A-9, for the Expansion Scenario. The IHS supply forecast was presented in Section I. The capacity shown in Figure A-9 is at the end of each year. Western Canada crude deliveries in the Base Case supply forecast increase from 3.3 million B/D in 2013 to 5.1 million B/D in 2020 and to 6.6 million B/D in 2030.

Figure A-9 - Western Canadian Supply for Pipeline Export vs. Pipeline Capacity



Takeaway capacity in 2013 is estimated at 3 million B/D. IHS estimates that there will be insufficient takeaway capacity until 2016. The use of rail is assumed to supplement pipeline takeaway capacity to meet this requirement. Rail loading of crude in Western Canada is estimated to reach its maximum in 2015. From 2016 through 2020, pipeline capacity expansions and new build projects will result in surplus pipeline capacity, which will exist until supply growth catches up. The addition of KXL capacity (2016), the TMEP and the Energy East project (2017) and the Northern Gateway project (2018) in the Expansion Scenario would result in surplus takeaway capacity. Surplus capacity is estimated to reach a maximum value of 1.8 million B/D in 2019. By 2030, surplus pipeline capacity is projected to be absorbed.

Table A-13 presents the IHS analysis of available Western Canadian and U.S. northern tier crude supply for the Expansion Scenario, as well as designated dispositions and remaining supply. The U.S. northern tier has been included in the analysis because capacity on some export pipelines is allocated to “on-ramps” for Williston Basin crude production. Included in the designated dispositions are crude deliveries to markets in Western Canada and Ontario, PADD I, PADD II (Upper Midwest only) and PADD IV. These are markets with either advantageous access to Canadian crude supply or limited practical alternatives for supply. Committed volumes of 728,000 B/D are estimated by 2013 in the Enbridge Spearhead and TransCanada Keystone pipelines.

TABLE A-13
CRUDE SUPPLY VERSUS PIPELINE CAPACITY - BASE CASE SUPPLY
(Thousand Barrels Per Day)

	2012	2013	2014	2015	2016	2017	2018	2019	2020	2025	2030	2035	2037
Supply [1]	3,860	4,344	4,686	4,982	5,382	5,765	6,063	6,309	6,480	7,328	7,825	8,483	8,673
Disposition													
Subtotal Advantaged Markets	1,728	1,697	1,687	1,725	1,720	1,719	1,722	1,724	1,726	1,714	1,677	1,610	1,690
Subtotal Term Committed Volumes	728	728	728	728	728	728	728	728	728	728	728	728	728
Potential Term Committed Volumes [2]													
Enbridge Gulf Coast Access	-	-	219	439	439	439	439	439	439	439	439	439	439
TCPL Keystone XL (KXL)	-	-	-	-	187	498	747	747	747	747	747	747	747
Enbridge Line 9	-	-	113	225	225	225	225	225	225	225	225	225	225
Trans Mountain Expansion Project	-	-	-	-	-	177	420	640	707	707	707	707	707
TCPL Energy East	-	-	-	-	-	62	400	600	800	900	900	900	900
Enbridge Northern Gateway	-	-	-	-	-	-	223	446	446	446	446	446	446
Subtotal Potential Term Committed Volumes	-	-	332	664	851	1,400	2,454	3,097	3,364	3,464	3,464	3,464	3,464
Total Designated Dispositions	2,456	2,425	2,747	3,117	3,298	3,847	4,904	5,549	5,818	5,906	5,869	5,802	5,882
Remaining Supply [3]	1,403	1,919	1,939	1,866	2,084	1,917	1,159	760	662	1,422	1,957	2,681	2,790

Notes: (1) Includes Western Canada and U.S. Bakken production, from IHS Base Case forecasts, August 2013.
(2) IHS estimates.
(3) Supply potentially available for Trans Mountain (for PADD V PNW), Enbridge (mainline) or Express (for Platte), spot deliveries to other pipelines or rail.

Term volume commitments on proposed projects would reduce available supply for spot shipments. Line 9 would deliver approximately 225,000 B/D to the Quebec refineries starting in 2014. KXL (shown with deliveries commencing in 2016) has estimated total volume commitments of 657,000 B/D. Starting up in 2017, TMEP would increase capacity to the West Coast with 707,000 B/D of commitments. Energy East would start up in 2017 to inland markets, and to 2018 to the East Coast. Northern Gateway has been included with potential term commitments starting in 2018.

Remaining supply in Western Canada and the U.S. northern tier, shown in Table A-13 is the volume of crude available for delivery on Trans Mountain to the Pacific Northwest region, the Enbridge mainline or Express (for delivery on the Platte system), as well as spot deliveries on pipelines with set-aside capacity for this purpose, and rail. For comparison, crude demand in these markets is forecast to be relatively stable at about 1.6 million B/D. The remaining supply is an indicator of the pressure on the crude supply/demand balance, and is used to inform the IHS crude price forecasts, which are described later.

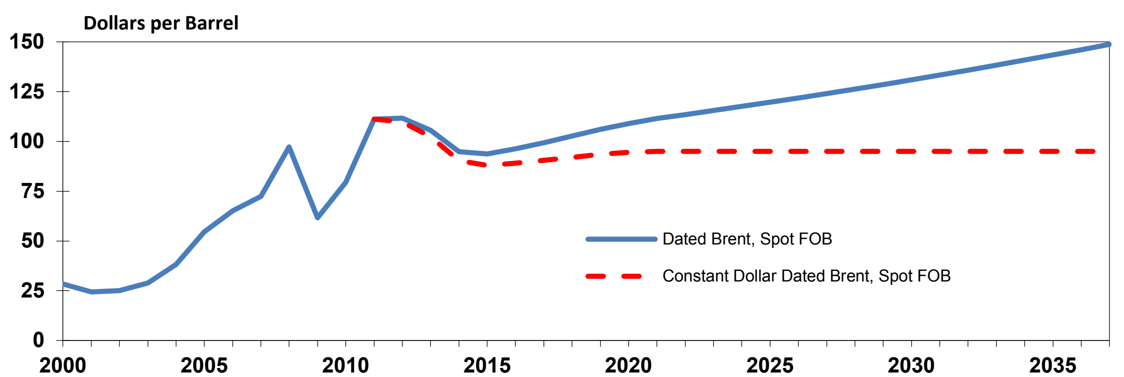
The future outlook for remaining supply is a function of input assumptions for the potential term commitments identified above. In 2013, the remaining supply in Western Canada is estimated at about 1.9 million B/D. Increased crude supply through the end of the decade is estimated to be offset by term commitments on new pipeline projects. As a result, with the proposed expansions and new projects proceeding before 2020, the estimated remaining supply is estimated to be reduced to about 662,000 B/D in 2020. Remaining supply grows thereafter, mainly due to bitumen production growth.

V. CRUDE OIL PRICING

The IHS crude pricing forecast methodology begins with the price of Dated Brent crude oil. This is the starting point in our methodology of projecting crude price differentials. Brent is a light sweet crude oil which can be processed by most refineries, and which competes with Middle Eastern and African crudes serving all major markets.

Figure A-10 presents the Brent price history and forecast, in current and constant 2012 dollars. Over the past two years the average annual price for Brent has been about $111 per barrel. This is the highest average price level for crude oil in recorded history, either in nominal (current) dollars or on an inflation-adjusted constant dollar basis. Our current long-term oil price outlook has Brent crude oil declining from these record levels to an annual average of about $94 by 2015 ($88 in real 2012 dollars) before rebounding.

FIGURE A-10
DATED BRENT PRICE FORECAST



In 2013 - 2015, we expect the "call on OPEC" to grow just slightly.[28] Although world demand growth is expected to be strong, the increase in non-OPEC crude production and other liquids growth is robust enough to meet most of it. OPEC productive capacity will also increase over the next few years, with much of the growth in Iraq. During this period, we expect downward pressure on prices.

As prices moderate, we expect less upstream investment compared with an environment of continuously rising prices. The lower level of capital expenditures will reduce the pace of non-OPEC supply growth later this decade, something the markets will anticipate and reflect with rising prices. Therefore we expect prices to rebound to

[28] The "call on OPEC" is the difference between global crude oil demand and non-OPEC crude oil supply.

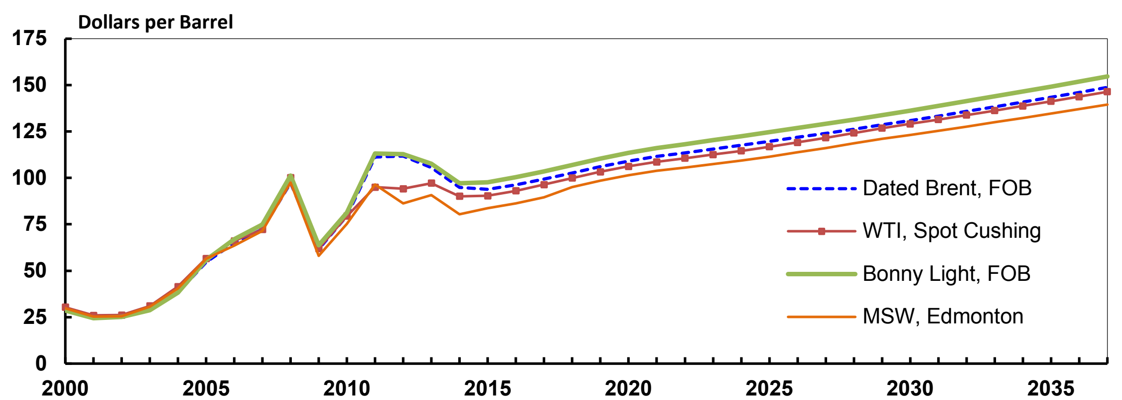
about $95 per barrel in real terms by 2020, remaining flat for the rest of the outlook horizon. In nominal terms, this results in a price of $142 per barrel by 2035.

Once the Brent price level is established, other crude prices can be determined through a combination of location and quality differentials. Price adjustments are also applied as needed based on specific market conditions or structural constraints. Crude quality differentials are based on refining economics and the connection between crude oil price spreads and refined product prices. The marginal refining configuration in a given region is used to estimate the value difference between two crude oils. Product pricing relationships, in particular light/heavy product pricing relationships, largely determine the value difference between crude oils. At the same time, refined product price relationships and differentials are based in part on crude prices and crude balances.

V-1. WTI-BRENT DIFFERENTIAL

Figure A-11 presents the outlook for selected light sweet crude oils, including Brent, West Texas Intermediate ("WTI"), Bonny Light and Alberta Mixed Sweet Blend ("MSW"). The crudes shown in the figure are discussed later.

FIGURE A-11
LIGHT CRUDE OIL PRICE FORECAST



Since 2010, surging tight oil production in North America has changed historical benchmark crude oil pricing relationships. The most conspicuous change has been the relationship between WTI and Brent, with WTI trading well over $20 per barrel below the Brent North Sea price during much of 2011, 2012, and early 2013. Prior to 2010, the WTI price at Cushing, OK maintained its connection to international oil prices because of the need for inland U.S. refining markets to supplement their crude supply with offshore imports (which were delivered to the region from the Gulf Coast via northbound pipelines). However, since 2010, growth in U.S. and Canadian supply has overwhelmed local refinery demand in markets in and around Cushing, depressing WTI prices and disconnecting WTI from international prices (represented by Brent).

The solution to this situation has been the revitalization of the link between Cushing and the international market via southbound pipelines, so surplus crude oil in and around Cushing can access the large refining market on the Gulf Coast. Several projects have been completed or are in progress, as summarized in Table A-11. These projects should provide ample capacity for crude supply around Cushing to transit to the Gulf Coast. We forecast that by the end of 2013, the WTI Cushing price will be around $5.50 per barrel below Louisiana Light Sweet ("LLS").[29] This represents the pipeline tariff cost (plus small differences in crude quality) to move crude from Cushing to the Gulf Coast.

V-2. LIGHT-HEAVY CRUDE PRICE DIFFERENTIAL

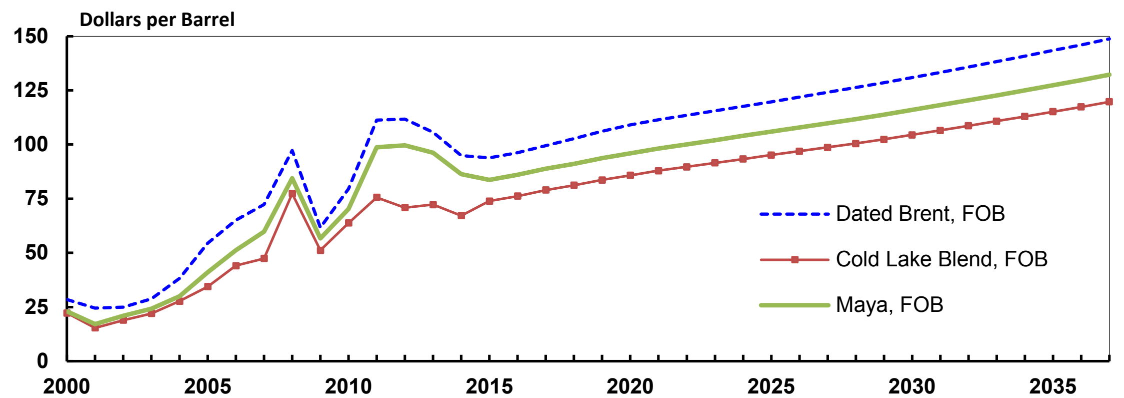
The price differential between light and heavy crude oil grades primarily reflects the price relationship between light refined products (such as gasoline and diesel) and heavy products (heavy fuel oil). In our methodology, the Brent and Maya differential is used as an indicator of the general trend in light-heavy crude oil price differentials. Light-heavy differentials are a key element in heavy crude production economics, refining margins, and refining investment.

The light-heavy product and light-heavy crude spreads are driven by refinery conversion economics. For example, when there is a need for the global refining system to keep pace with light product demand growth and add conversion capacity (through investment or increased utilization), light product prices strengthen relative to heavy fuel oil, which increases margins for conversion refineries able to upgrade heavy fuel oil into light products.

Maya is the basis for analysis of Western Canadian heavy crude prices in North America. The long term forecast for Maya, FOB is presented in Figure A-12. Cold Lake Blend is priced in North American markets. While its price can be related to Maya there are a number of factors, including logistical constraints, which can contribute to wide discounts. This situation has existed since 2010.

[29] Light Louisiana Sweet ("LLS") is the key domestic light sweet crude grade in the U.S. Gulf Coast.

FIGURE A-12
HEAVY CRUDE OIL PRICE FORECAST



V-3. PRICE RELATIONSHIPS FOR WESTERN CANADIAN CRUDE OILS ON THE U.S. WEST COAST

The relationship of crude oil prices on the U.S. West Coast to other regional and international markets has reflected the regional supply/demand balance. ANS is a light sour crude produced in PADD V. Given that PADD V will increasingly depend on imported crude supplies, the IHS outlook for ANS price reflects parity values that are consistent with delivered Middle East crude.

U.S. West Coast refineries could import more Canadian crudes if they were priced competitively and sufficient transportation infrastructure was available. Opportunities exist for oil sands crudes, as described in Section II-4. Price relationships for oil sands crudes on the West Coast are described below. The potential impact of West Coast pricing on Alberta netback prices is discussed later in this section.

Light Sweet SCO

Light sweet SCO, such as Syncrude SSP, has no vacuum residue so it has a higher refining value than ANS and other light sour crudes based on cracking refinery yields. IHS does not expect that sweet bottomless SCO will have a significant market in California coking refineries. On the other hand, cracking refineries in Washington State can use SCO, and do so if it is priced competitively. IHS values SSP in Washington State against a Middle East light sour import barrel. Price discounts since 2010, due to pipeline constraints in inland markets, have affected SCO as well as conventional light crude, making it more attractive to refiners in the region. IHS forecasts prices of SCO based on clearing the market in the Midwest, so it is normally priced attractively for Washington State. Any future price discounts due to growing SCO availability would make the crude more attractive in Washington State, compared with its refining value.

Heavy Blends

California is expected to require a growing amount of imported heavy crude. IHS forecasts prices there for Canadian heavy blends including Cold Lake Blend ("CLB" or "DilBit"), using the valuation principles described above. IHS forecasts the prices of Canadian bitumen blends in California based on the price of a Middle East light sour import barrel, which values imports appropriately against the incremental supply for the region. DilBit has a higher content of vacuum residue than light sour crudes, so its refining value is lower. Trans Mountain delivers heavy crude through its Westridge Marine Terminal which may be shipped to the California market. As noted in Section II-4, California refineries have been increasing imports of Western Canadian crude. This trend is expected to continue.

V-4. PRICE RELATIONSHIPS FOR WESTERN CANADIAN CRUDE IN ASIA

Canadian crudes are currently available to the Asian market via Trans Mountain's Westridge Marine Terminal. If additional pipeline capacity is built to the Canadian West Coast, more Canadian crudes could be shipped to Asia. The TMEP would provide additional capacity for the Asian market.

In its global analysis, IHS prepares estimates for the balance of crude oil flows in the world, on an overall basis and by major quality grade. Many Asian countries have indigenous crude oil production. However, Asia imports most of the crude required to meet refined product demand. The majority of Asian imports are from the Middle East, although imports from West Africa are rising. Arab Light and Bonny Light are used as the light sour and light sweet marker crudes in the Asia-Pacific region, respectively.

Western Canadian crudes that could be available for the Asian market include light conventional crudes, sweet SCO, conventional heavy and bitumen blends. In addition, other grades of crude that could be tailored to the needs of the Asian refineries may be produced. Light grades could be of interest in Japan, China and other countries, whereas a heavy blend would most likely be used in China and India. This was described in Section III.

Light Sweet SCO

Sweet SCO such as Syncrude SSP may be expected to compete with conventional light sweet crude in North Asian markets. The price for the benchmark light crude, Bonny Light, is likely to serve as the basis for establishing sweet SCO prices in the region.

Sweet SCO has a high proportion of VGO, which would become low sulphur residual fuel oil ("RFO") in a relatively simple (hydroskimming) refinery. There are large RFO markets in Asia. As a result, we estimate the refining value of SCO to be near that of Bonny Light. IHS believes there would also be opportunities to enhance market potential through alternative formulations of light sweet SCO with less VGO. Such a crude would have more value in a hydroskimming refinery, and might also prove attractive to refineries in Asia with cracking configurations.

Heavy Blends

Refineries in Northeast Asia currently use relatively small volumes of heavy crude, and any heavy crude being processed is not likely to be as heavy as oil sands blends such as DilBit. Most of the current heavy crude use in Asia is in China. Trans Mountain is understood to have delivered heavy crude for Asian markets on a spot basis.

IHS believes that significant future potential exists to place growing volumes of Western Canadian heavy crude in Asia. Heavy crude processed by Asian refineries would likely be marketed under long-term supply agreements or through structural arrangements between companies with common ownership. Refining capacity may be constructed or modified to use more heavy crude, particularly in China. The growth potential for heavy blends in Asia, particularly in China and India, was discussed in Section III.

V-5. CRUDE NETBACK PRICES IN ALBERTA

Netback values are forecast from markets in the Asia/Pacific region, including the U.S. West Coast and Northeast Asia. The refining valuation principles for Canadian oil sands crudes in California, Washington State and Asian markets were discussed in Section V-3 and Section V-4. Netback values depend on refinery gate prices and transportation costs from Alberta. The forecast netback values at Edmonton are presented in Table A-14, in current and constant 2012 dollars. The analysis summarized here is based on the IHS supply/demand balance, and our current estimate of pipeline tolls and tanker costs. The outlook is based on the pipeline infrastructure developments described in Section IV, which are included in the Expansion Scenario.

TABLE A-14
OIL SANDS NETBACK VALUES AT EDMONTON [1]
(U.S. Dollars per Barrel)

	2018	2019	2020	2021	2022	2023	2024	2025	2030	2035	2037
Inflation Factor (2012 = 1.00)	1.10	1.11	1.13	1.15	1.17	1.20	1.22	1.24	1.35	1.48	1.54
Current U.S. Dollars per Barrel											
Sweet SCO											
From Midwest / USGC [2]	103.05	106.60	109.71	112.23	114.26	116.32	118.42	120.72	133.56	146.32	151.70
From Washington	110.48	114.20	117.38	120.21	122.43	124.75	127.09	129.38	141.76	156.29	162.44
From Japan	104.68	108.27	111.42	114.04	116.18	118.38	120.61	122.87	134.77	147.94	153.50
Cold Lake DilBit											
From Midwest / USGC [2]	81.21	83.65	85.76	87.90	89.70	91.53	93.34	95.16	104.45	106.48	110.56
From California	84.89	87.85	90.45	92.70	94.38	96.19	97.98	99.70	109.23	120.39	125.11
From China	86.12	89.12	91.66	93.89	95.60	97.41	99.21	100.97	110.56	121.80	126.56
Forecast in Constant 2012 U.S. Dollars per Barrel											
Sweet SCO											
From Midwest / USGC [2]	93.95	95.63	96.77	97.31	97.32	97.32	97.34	97.48	98.64	98.62	98.59
From Washington	100.73	102.44	103.54	104.23	104.28	104.38	104.46	104.47	104.70	105.34	105.57
From Japan	95.44	97.12	98.28	98.88	98.96	99.04	99.13	99.21	99.53	99.72	99.75
Cold Lake DilBit											
From Midwest / USGC [2]	74.04	75.04	75.65	76.21	76.40	76.58	76.72	76.83	77.14	71.77	71.85
From California	77.39	78.81	79.78	80.38	80.39	80.48	80.53	80.50	80.67	81.15	81.30
From China	78.52	79.94	80.85	81.40	81.43	81.50	81.54	81.53	81.65	82.10	82.24

Notes: (1) Netback values assuming price parity at each market location; not a forecast price unless noted.
(2) Indicates IHS forecast price.

Table A-15 provides estimated transportation costs for crude delivery from Edmonton to identified Pacific markets in 2017. Costs include estimated TMEP tolls and waterborne tanker transportation charges. For this analysis, and to be conservative, the use of Panamax tankers is assumed. If Aframax tankers are utilized, then per barrel costs for waterborne transportation would be reduced.

TABLE A-15
TRANSPORTATION COSTS FROM EDMONTON TO PACIFIC - 2017
(U.S. Dollars per Barrel)

		Tanker		
Crude/Market	Trans Mountain Toll [(1) (2)]	Size	Rate	Total
Light Crude				
Japan (Yokohama)	4.36	Panamax	3.12	7.48
Singapore	4.36	Panamax	4.65	9.01
Heavy Crude				
California	4.42	Panamax	1.54	5.96
China (Shanghai)	4.42	Panamax	3.52	7.95
India (Jamnagar)	4.42	Panamax	6.36	10.78

Notes: (1) Based on Trans Mountain Expansion Project TSA, for annual term deliveries < 75,000 barrels
(2) Converted from $CDN at assumed exchange rate of 0.92 $US/$CDN

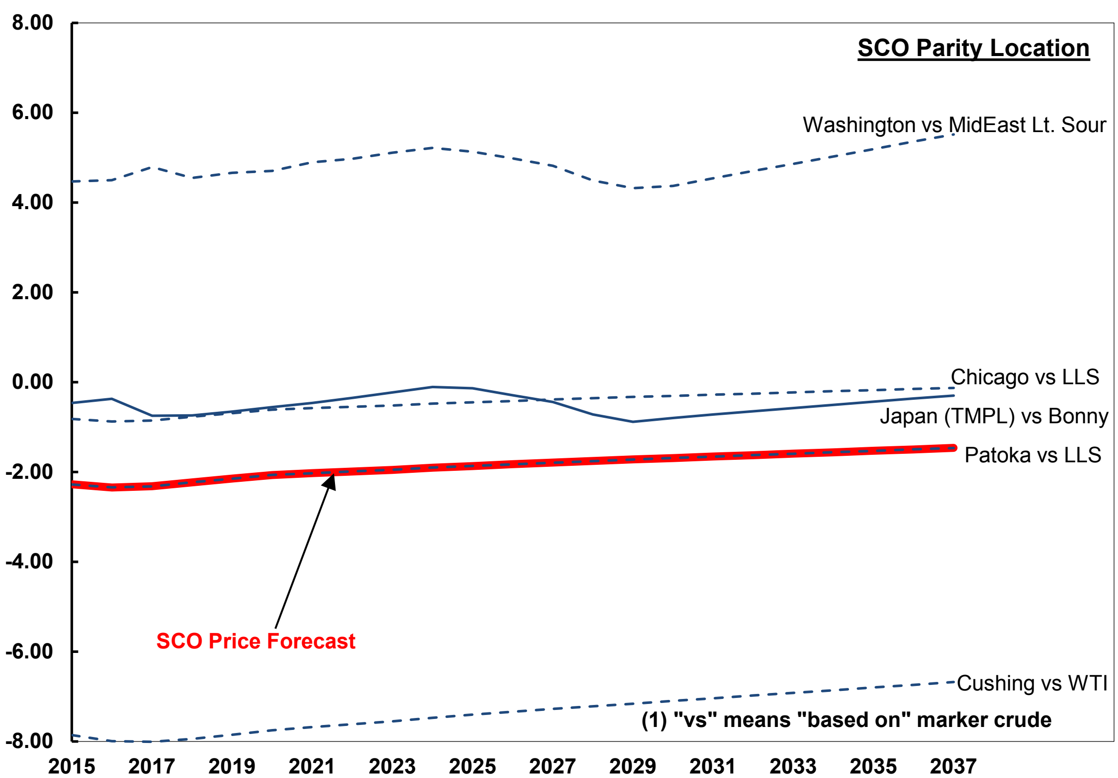
LIGHT SWEET SCO NETBACK PRICES

Light sweet SCO production is expected to grow at a relatively slow pace through 2020, due to the cancellation or postponement of upgrader projects in Alberta. Despite this, new SCO projects in 2009 and 2010 have increased supply, so the availability of segregated SCO is forecast to increase through 2020. As a result, the price of SCO is forecast to weaken toward Patoka parity versus LLS by 2015, and remain at that level through the forecast period.

To assess the potential impact of netback prices from other market locations, IHS evaluates Syncrude SSP prices in the U.S. Midwest, Washington State as well as Japan. The Edmonton netback values from different market locations are compared with the IHS price forecast in Figure A-13. Chicago and Patoka netback prices assume parity with LLS rather than WTI, as this would likely be the crude processed in these locations.

Based on our price forecast (denoted by the red line in Figure A-13), SCO should be attractive to refineries in Washington State and northern PADD II (around Chicago). SCO should also be attractively priced for refineries in Japan using Trans Mountain (based on estimated future TMEP tolls) through Vancouver.

FIGURE A-13
SCO, EDMONTON - LLS, ST. JAMES
(Constant 2012 US Dollars per Barrel)

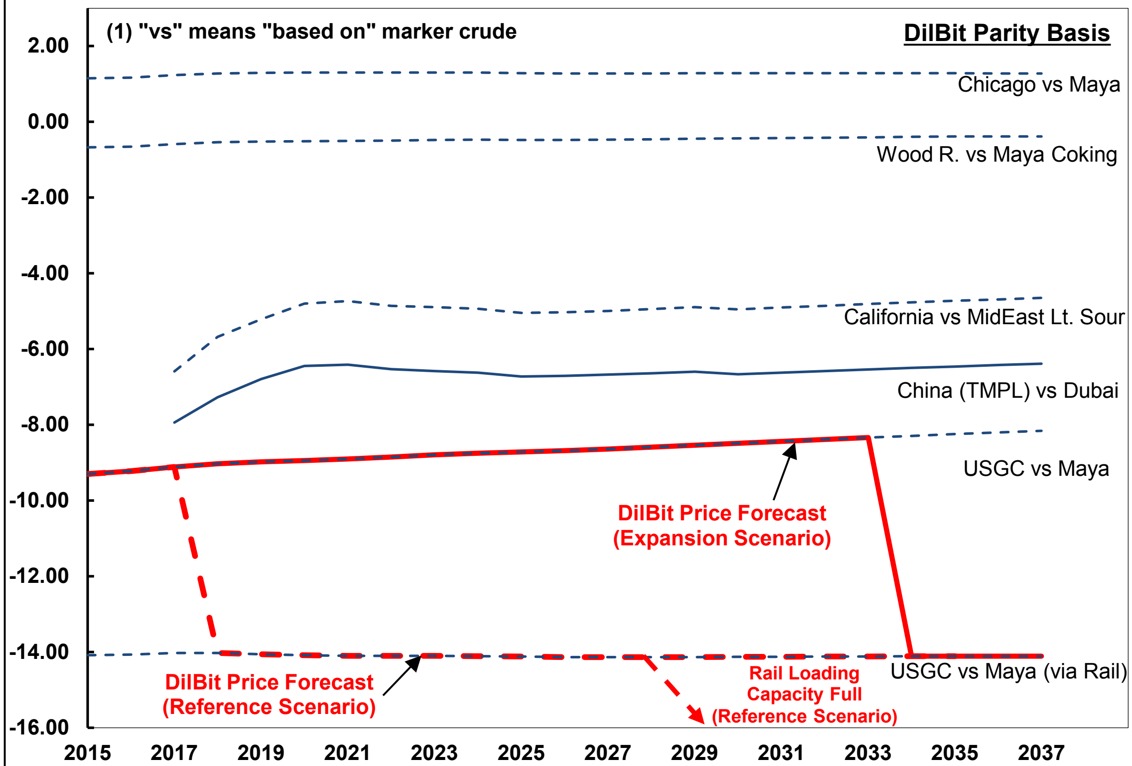


COLD LAKE DILBIT NETBACK PRICES

The historical growth in supplies of Canadian heavy crude blends, combined with recent infrastructure developments, means that some of this crude now reaches the U.S. Gulf Coast. IHS expects Canadian prices to strengthen from 2013 to 2016, due to more refinery coking capacity and additional crude pipeline capacity such as the Enbridge Flanagan South / Seaway projects. The CLB (DilBit) price is forecast to strengthen to U.S. Gulf Coast parity with Maya by 2016. The basis for the calculated netback is the Enbridge-Pegasus pipeline routing. The CLB price is expected to remain at U.S. Gulf Coast parity in the Expansion Scenario, based on pipeline transportation costs. However, starting in 2033, we estimate that there will be excess supply of crude for pipeline disposition; the Edmonton price is forecast to weaken to the equivalent of a rail transportation netback from the U.S. Gulf Coast as a result. Prior to 2033, a tight balance for heavy crude suggests that prices would be set by Gulf Coast parity on a spot pipeline delivery basis. The uncommitted tolls on Keystone XL are not known at present, but may become the price-setting basis for Canadian heavy crude during this period if the tolls are lower.

DilBit netback prices versus benchmarks in the U.S. Midwest, California, China and the U.S. Gulf Coast are compared in Figure A-14. At the U.S. Gulf Coast netback price, DilBit would be attractive to heavy crude refineries in the U.S. Midwest. IHS assessed the value of DilBit in California, as this is considered to be a potential growth market for heavy bitumen blends. Based on the U.S. Gulf Coast parity price, refineries in California should find DilBit to be priced attractively. This should support further growth in deliveries to this market. DilBit is also estimated to be priced competitively in China throughout the forecast period, based on the TMEP term toll.

FIGURE A-14
COLD LAKE BLEND, EDMONTON - MAYA, FOB
(Constant 2012 US Dollars per Barrel)



Our forecast of the CLB netback price in the Reference Scenario, without the major export pipelines (TMEP, Energy East and Northern Gateway) is shown in Figure A-14. IHS estimates that the available supply of heavy crude in this case is in excess of the pipeline capacity to connected markets. As a result, the netback price is shown weakening to the equivalent of the rail netback price from the U.S. Gulf Coast, for an extended period, beginning as early as 2018.

Furthermore, the IHS analysis of the balance for this scenario suggests that the current rail loading capacity would be inadequate to handle the volume of surplus crude well before 2030. This indicates that prices may weaken below the U.S. Gulf Coast rail parity price, which is directionally shown in Figure A-14. In our opinion, this could again give rise to the type of extraordinary discounts observed in recent years for Canadian heavy crude.

V-6. IMPLICATIONS OF NETBACK PRICING RESULTS

The availability of bitumen blends is forecast to increase through 2037. The marketed supply of crude oil will depend on the production of raw bitumen, upgrading project developments, and the availability of suitable diluent streams. Comparative netback pricing in Alberta for the major oil sands marketed streams has been broadened to include potential markets in the Asia/Pacific region, which may become accessible via TMEP. The opportunity to deliver oil sands crudes to refineries in California and several Asian countries would be facilitated by such developments. As noted previously, an increasing need for imported crude oil supplies is expected in these regions. TMEP provides access to these growth markets.

As noted in Section V-5, DilBit should be attractive in California and China for the forecast period. Trans Mountain is already delivering heavy crude for markets in the Pacific Rim. The results presented above suggest that crude deliveries to these markets should increase due to favourable pricing. IHS notes that the volume of Canadian oil sands crude that eventually reaches these markets over the forecast period will depend on refining economics and on other factors. These include the pace and extent of other infrastructure developments, product market and quality considerations, the availability of suitable refinery capacity, tanker and pipeline transportation costs, environmental legislation across jurisdictions and in some cases, the ability of industry participants to conclude commercial arrangements for strategic long-term supply.

APPENDIX B: RESUME OF PROFESSIONAL QUALIFICATIONS STEVEN J. KELLY

EDUCATION

B.Eng. Chemical Engineering from McMaster University (Hamilton, Ontario) in 1982.

M.Eng. Chemical Engineering from McMaster University (Hamilton, Ontario) in 1985.

M.B.A. from University of Calgary (Calgary, Alberta) in 1998.

PROFESSIONAL ASSOCIATIONS

Association of Professional Engineers and Geoscientists of Alberta (APEGA)

Canadian Heavy Oil Association

CURRENT POSITION

Vice President, Downstream Energy Consulting, IHS Calgary

WORK EXPERIENCE

Mr. Kelly joined Purvin & Gertz (acquired by IHS in 2011) in 1996, and has applied his experience in the analysis of crude oil and petroleum markets as a consultant for more than 17 years. His focus has been on markets in Canada, the U.S. Midwest and the Pacific Rim. Mr. Kelly has assisted numerous crude oil producers in the development of marketing strategies. His experience includes projects for a variety of conventional light, heavy and synthetic crude oils. Through these assignments, Mr. Kelly has developed significant expertise in heavy crude upgrading. Mr. Kelly has significant experience with logistical issues, and has assisted clients in a range of petroleum transportation studies. In addition, he has worked with Purvin & Gertz study teams in the simulation and modeling of refineries and has assisted clients in a number of competitive analysis studies.

Mr. Kelly managed the firm's European market analysis activities while on a foreign assignment (August 2001 through July 2005). He returned to Calgary in July 2005 and assumed the role of Calgary office manager in January 2006.

Mr. Kelly joined Purvin & Gertz from Shell Canada Limited, where he was involved in manufacturing and supply optimization activities at their corporate headquarters. In that capacity, he identified short-term profitability opportunities for Shell's Canadian refining operations. He participated in several strategic planning and re-engineering studies, and has extensive experience with the use and construction of optimization models. Mr. Kelly worked as a refinery operations engineer at Shell's Scotford Refinery. Mr. Kelly has a graduate degree in process control, and has developed applications for a wide range of refinery units. Prior to joining Shell Canada, Mr. Kelly was employed by Polysar Limited for two years at its Sarnia manufacturing facility, as a process engineer.

REPRESENTATIVE MAJOR PROJECT EXPERIENCE

MARKET ANALYSIS

- **CRUDE OIL & OIL SANDS MARKET OUTLOOK –** Mr. Kelly was a co-developer of this service, which presented long range outlooks for North American crude oil supply, disposition and pricing, with a focus on the Canadian oil sands. The service included detailed crude balances and refining industry analysis, as well as regional crude and refined products pricing and refining margins.

- **GLOBAL MARKETS FOR CANADIAN OIL SANDS CRUDES –** Mr. Kelly directed this major multiclient study, which investigated supply, disposition and pricing issues for a range of crudes available from the Canadian oil sands. The study considered markets in North America and selected Northeast Asian countries, economics of various upgrading configurations, production and trade scenarios, and analysis of infrastructure requirements for Canadian crude exports.

- **GLOBAL PETROLEUM MARKET OUTLOOK –** Mr. Kelly has prepared many contributions to this major multi-client service. The service covered refined product demand projections for each country, trade balances, and refining industry analysis. Mr. Kelly completed detailed analysis of petroleum demand projections for Europe (while on an overseas posting), and contributed to the analysis of the North American petroleum outlooks.

- **INTRODUCTION TO UPGRADING, REFINING & ECONOMICS COURSE –** Mr. Kelly developed the content and manages this two-day course, and participates as an instructor. The course provides attendees with a unique introduction to the downstream petroleum sector, with particular focus on issues of interest to Canadian oil sands industry players. The course has been offered twice annually since 2008.

- **EUROPEAN MARKET ANALYSIS –** Mr. Kelly had responsibility for the European edition of Purvin & Gertz' monthly Crude Oil & Refining Outlook service while on an overseas posting. This multi-client service provides ongoing analysis of European products supply/demand trends and refining operations, and develops projections of refining margins and crude oil and refined product prices.

- **OUTLOOK FOR RUSSIAN PETROLEUM TRADE TO EUROPE –** Mr. Kelly directed this multi-client study that investigated regional demand and trade issues for

Europe and adjacent Commonwealth of Independent States. Crude oil production and logistics in Russia were evaluated, as a driver of refining activity and product surpluses. The study included regional balances for Russia and the interface countries, as well as pricing dynamics for crude oil and products at selected points within Russia.

- **CRUDE OIL & REFINING OUTLOOK –** For five years, Mr. Kelly prepared the U.S. Midwest/Canadian edition of this monthly multi-client service, which provided in-depth analysis of the supply/demand balance for Canadian crudes, and equilibrium pricing relationships between benchmark crudes. Mr. Kelly was responsible for ongoing monitoring of U.S. Midwest petroleum product markets, including supply/demand balances, pricing and refining margins.

- **INTERNATIONAL CONDENSATE SUPPLY/DEMAND –** As part of a wide-ranging study of LPG and condensate markets, carried out in support of a proposed investment in North African exploration and production, Mr. Kelly analyzed international condensate production projects, splitting/refining projects, and condensate demand trends. Analysis included development of inter-regional trade matrices, which were used in conjunction with other information to assess the price setting mechanisms for various condensates.

- **HEAVY CRUDE MARKET STUDY –** Mr. Kelly was the director of a large multiclient study, which investigated supply, disposition and pricing issues for heavy crude. The scope of the study covered Western Hemisphere production regions, and considered the key market regions in Canada and the U.S. Strategic issues facing market participants were investigated.

- **NATURAL GAS/NGL MARKET ANALYSIS –** Mr. Kelly has been involved in a number of studies related to natural gas and NGL markets. Studies have included an evaluation of supply/demand fundamentals and forecasts of North American regional natural gas prices. Mr. Kelly has also prepared long-range natural gas and NGL price forecasts.

CRUDE OIL/REFINED PRODUCTS MARKETS AND LOGISTICS

- **WILLISTON BASIN CRUDE MARKET STUDY –** The market and logistical forces behind severe discounting of crude produced in the Williston Basin area of Montana and North Dakota were studied for an industry group by a Purvin & Gertz team led by Mr. Kelly. The study estimated the impact of proposed pipeline solutions and the potential for restrictions on pipeline crude qualities.

- **NORTH DAKOTA REFINING CAPACITY ANALYSIS –** Steven led PGI's activities for this study. Purvin & Gertz was part of a study team that evaluated the implications of additional refining capacity potentially being developed in North Dakota. PGI's analysis included crude oil and refined products price impacts, and was based on logistical optimization models developed for the assignment.

- **CRUDE EXPORT PIPELINE QUALITY BANK DESIGN –** PGI advised a consortium on the design of a quality bank for a major crude export pipeline. Mr. Kelly managed Purvin & Gertz activities on this assignment, which included identification of potential crude oils that may be served by the pipeline, and analysis of different options for the mechanism of the quality bank and formulation of proposals to the consortium.

- **CRUDE OIL MARKETS AND PRICING FOR CASPIAN CRUDE –** On behalf of a consortium of crude oil producers in the Caspian region, Steven directed a study of the likely markets for the potential export stream. Markets analyzed included Europe, the Far East, the U.S. and Latin America. Pricing projections were based on full refining value analysis from available crude assay data. Netback values to the assumed load port were calculated.

- **CRUDE OIL VALUATION AND MARKETING –** Steven has undertaken several assignments to value new crude oil production streams relative to internationally traded crudes. In many cases the value of the new crude has been developed both as a stand-alone production stream and as a component of a commingled stream in a common carrier pipeline system. This work has also involved assisting in developing marketing strategies, identifying potential buyers with favorable logistics and appropriate refining capacity.

- **CRUDE EVALUATION MODELLING –** Mr. Kelly participated on a Purvin & Gertz study team that prepared models of refining valuations for a major Middle Eastern crude producer. His objective in this study was to define refinery configurations for the European markets that could potentially process crude oil from the client, and develop real-time models for refining value differentials against defined benchmark crude oils.

- **CRUDE OIL MARKET ANALYSIS –** Mr. Kelly has developed refining values and comparative economics for many North American, North Sea and various other international crude oils. This work has been completed in numerous single client projects. Through this work Mr. Kelly has developed specific expertise in the valuation of synthetic crude oils.

REGULATORY ASSISTANCE

- **PIPELINE TOLL HEARING –** Mr. Kelly acted as an independent expert in a toll hearing before the National Energy Board, relating to the proposed tolling methodology for a major capacity expansion to an existing pipeline system in Western Canada. He prepared direct evidence, provided advice and input for information requests, and provided oral testimony at the hearing.

- **THROUGHPUT ANALYSIS –** Mr. Kelly led the firm's activities in support of a National Energy Board application being prepared by a pipeline company with operations in Western Canada. PGI developed throughput forecasts for the pipeline under a range of input premises.

- **PIPELINE TOLL HEARINGS –** Mr. Kelly provided consulting assistance to an intervenor in two separate regulatory applications relating to a crude oil pipeline in Eastern Canada. He prepared direct evidence relating to alternative uses of the pipeline facilities, and participated in the information request process. In each case, the matter was resolved prior to proceeding to an NEB oral hearing.

- **PIPELINE TOLL HEARING –** Mr. Kelly provided consulting assistance to an intervenor in a regulatory application relating to a crude oil pipeline in British Columbia. He prepared direct evidence relating to future utilization of the pipeline, and participated in the information request process. The matter was resolved prior to proceeding to an oral hearing.

- **PIPELINE FACILITIES HEARING –** As part of a study team engaged by a group of producers, Mr. Kelly participated as an independent expert in a facilities hearing before the National Energy Board, relating to the proposed reversal of an oil pipeline in Eastern Canada. He prepared direct evidence, provided advice and input for information requests, and provided oral testimony.

- **LEADED GASOLINE ADDITIVES –** Steven led the company's activities in providing consulting support to a legal firm, engaged in a dispute relating to a supply contract for the leaded gasoline additive, tetraethyllead (TEL). This involved analysis of the technical and commercial aspects of TEL production, and review of global markets for leaded gasoline.

STRATEGIC BUSINESS ADVICE

- **PORT STRATEGIC PLAN –** A North European port commissioned Purvin & Gertz to conduct a strategic planning study. Mr. Kelly led the study. In light of potential changes in the port's business environment, the assignment focused on identification and ranking of alternative businesses that could be developed at the facility. Purvin & Gertz provided an analysis and ranking of a wide range of options, after evaluating the business environment.

- **FUELS REFINERY INVESTMENT ANALYSIS –** A European refiner facing significant refinery investments to produce ultra-low sulphur fuels commissioned Purvin & Gertz to evaluate several alternatives. Mr. Kelly led the company's efforts to simulate current refinery capabilities, using a proprietary optimization model. A detailed analysis was completed, to assess the impact of each alternative on the forecast refining margin.

- **CRITICAL REVIEW OF BUSINESS PLAN –** As part of an independent review of a proposed privatization, Steven was required to review the future earning projections relating to petroleum retailing outlets in India. Opinions were developed to realistic target penetrations that could be achieved and issues were raised concerning the impact of delays in foreseen regulatory changes.

- **EUROPEAN LIGHT PRODUCTS MARKETS STUDY –** In support of a client's analysis of condensate disposition options, Mr. Kelly was closely involved in an analysis that studied a range of alternatives to process or to sell a new condensate stream. In addition to analyzing refining investments and economics, the study examined the outlook for markets for light products, and particularly for gasoline and naphtha markets.

- **REFINING STRATEGIC STUDY –** A refiner with multiple operations engaged Purvin & Gertz to analyze its competitive position among its peer group. Detailed LP analyses were used to assess crude slate and product yield profitability of refineries in the study group. Study recommendations allowed the client to improve its competitive position.

- **MIDWEST/CANADIAN REFINING STRATEGIC STUDY –** As part of a study team, Mr. Kelly was involved in an evaluation of U.S. Midwest and Ontario refiners in the current and future business environment. Refineries were modeled using Purvin & Gertz' proprietary LP and operating cost models. Comparative margins were developed for each refinery. Regional profitability rankings were compiled, and a number of recommendations were tabled.

- **HEAVY OIL DILUENT STRATEGIC STUDY –** Mr. Kelly was part of a Purvin & Gertz study team engaged to evaluate strategic options for a heavy crude oil producer, relative to the availability and pricing of diluent. The results of the study included recommendations for strategic management of diluent supply.

- **CANADIAN REFINING INDUSTRY COMPETITIVENESS STUDY –** Mr. Kelly worked as part of a Purvin & Gertz study team, engaged to evaluate the competitiveness of the Canadian refining industry, in the current business climate and with varying degrees of fuel reformulation. Detailed LP models and operating cost models were prepared for the refineries in the study group. Cash flow models were developed to assess the impact of fuel sulphur reduction on these refineries. The strategic implications of fuel reformulation were assessed, for individual refineries and regional segments of the Canadian industry.

- **HEAVY CRUDE MARKET EVALUATION –** A group of heavy crude producers retained PGI to investigate potential market growth opportunities for heavy crude. Mr. Kelly was responsible for evaluating comparative refining values for key grades. He also estimated capital expenditures and processing economics for a number of refineries that were identified as candidates to run heavy crude.

- **BITUMEN UPGRADING STUDY –** Mr. Kelly developed a series of heavy oil upgrading schemes that were analyzed for a study evaluating opportunities to expand bitumen markets. The case studies were prepared for an industry group interested in a variety of options ranging from no field upgrading to full upgrading to synthetic crude. A key part of this assignment was the development of partial upgrading options, integration with petroleum refiners, and identification of the technical and economic issues associated with these types of projects.

- **SYNTHETIC CRUDE MARKET STUDY –** Mr. Kelly has directed and participated in numerous studies for current and potential Western Canadian synthetic crude producers. The studies have investigated strategic options for the expansion of existing refining markets for oil sands production. Through this work he has considered markets across North America, and modeled all potential synthetic crude refiners.

- **CLIMATE CHANGE OPTIONS PAPER –** Mr. Kelly directed a study that analyzed the cost and competitiveness impacts on the Canadian refining industry, of selected technical options for greenhouse gas emission reductions. The analysis included development of project capital and operating costs for all Canadian fuels refineries. GHG reduction potential and regional economic impacts on the industry were assessed, and an analysis of refinery viability under different policy options was developed.

Appendix B The Trans Mountain Expansion Project: Understanding the Economic Benefits for Canada and its Regions, The Conference Board of Canada

The Conference Board of Canada | Le Conference Board du Canada

CUSTOM REPORT

The Trans Mountain Expansion Project: Understanding the Economic Benefits for Canada and its Regions

Presented: November 30, 2013

Presented by: The Conference Board of Canada

Presented to: Trans Mountain Pipeline (ULC)

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Executive Summary

Oil is a global commodity, with a well established transportation infrastructure. As a result, global benchmark prices are usually nearly identical to one another once adjustments for quality and transportation costs are taken into account. However, this has not been the case in recent years, with Canadian benchmark prices lagging considerably behind their global peers. The combination of stagnant North American demand, rising North American production, and an oil transportation infrastructure that is largely confined to exporting Canadian production to the U.S. Midwest all contributed to this outcome. The result is that Canada has not been getting the full fiscal and economic benefits associated with exploiting its non-renewable oil resources.

In response, there has been growing interest in developing new oil pipeline infrastructure in North America. There are currently four major pipeline projects under consideration that would carry oil away from Western Canada if completed. One of these is the Trans Mountain Expansion Project (TMEP or the Project), which would nearly triple the capacity of the existing pipeline that runs from Edmonton, Alberta to Burnaby, British Columbia. The objective of this report is to assess the economic and fiscal impacts associated with the proposed expansion of the Trans Mountain pipeline. We do this in three ways:

- Assessing the impacts associated with the initial required investments to build the pipeline and related infrastructure.
- Assessing the impacts associated with operating the pipeline once it is up and running.
- Assessing the impacts associated with higher netbacks to oil producers that are expected to result from smaller price differentials between Canadian and international oil price benchmarks.

Impacts of TMEP's Development Phase

If approved, the TMEP is expected to cost approximately $5.5 billion[1], with the expenditures taking place over a seven-year period, from 2012 to 2018. If we adjust for price increases, that is equivalent to $4.9 billion in 2012 dollars. Parts of the Project, such as planning and regulatory fillings have already begun; however, the bulk of the spending is expected to take place in 2016 and 2017, when construction activity peaks. For the purposes of our analysis, we exclude the financing costs from the analysis; thus we assess the economic impacts of $4.6 billion of expenditures in 2012 dollars.[2]

This spending generates direct impacts in the construction sector, supply chain impacts associated with the inputs needed to complete the Project, and induced effects, which occur when the wages that employees earn from the direct and supply chain effects are spent. Combined, these three effects are expected to support 58,037 person-years of employment, with nearly half of those effects being direct,

[1] The Trans Mountain Expansion Application to the NEB provides an estimated capital cost for the Project of $5.4 billion; this reflects a reduction in the required investment associated with the expected contribution from Westridge Dock bid premiums, which do not reduce the total expenditures on of the Project for the purposes of this Report.

[2] All subsequent dollar figures are in 2012 dollars unless otherwise noted.

and the rest being indirect and induced. Most of the employment effects will occur in British Columbia (61.8 per cent) and Alberta (25.2 per cent), reflecting that this is where the pipeline will be built. However, Ontario (8 per cent), Quebec (2.4 per cent), and the other Prairie provinces (1.9 per cent) will also experience job gains.

The additional economic activity also generates fiscal effects at both the federal and provincial level. The development of the TMEP is expected to generate a total of $1.2 billion in federal ($646 million) and provincial ($568 million) government revenues. This is equivalent to $27 for every $100 of investment. The largest fiscal impacts are found in personal income taxes ($559 million), indirect taxes such as sales taxes ($335 million), and corporate income taxes ($184 million). Assuming that the federal tax revenues will be distributed across the provinces on a per capita basis, British Columbia ($394 million) and Ontario ($307 million) will experience the largest combined federal and provincial fiscal effects. Other regions of the country, such as Alberta ($239 million), Quebec ($166 million), and the Prairies ($58 million) will also experience fiscal benefits.

Impacts of TMEP's Operational Phase

Once operational, the TMEP will also generate positive economic and fiscal impacts on an ongoing basis. We assess the operational impacts of the pipeline over its first 20 years of service under two scenarios. The first considers the impact of only the long-term contracts that have been signed and can be considered the minimum impact associated with firm commitments. The second scenario assesses the economic impacts when the spot or non-firm capacity in the pipeline is fully utilized, and can be considered the maximum impact.

At a minimum, including the direct, supply chain, and induced effects we expect pipeline operations will support 50,273 person-years of employment, and this figure rises to 65,184 if the non-firm capacity is fully utilized. British Columbia (60.2 per cent) and Alberta (20.5 per cent) still experience the largest portion of the employment impacts. However, other regions of the country, such as Ontario (12.6 per cent), Quebec (3.9 per cent), and the Prairies (2 per cent) benefit from the employment impacts during the operational phase of the Project.

In terms of fiscal effects, pipeline operations are expected to generate between $2.5 and $3.3 billion in combined federal and provincial revenues over the first 20 years of operations. A key reason for this is that the oil pipeline industry generates large corporate income tax effects. Corporate profits account for the largest share of the revenues (60.1 per cent), followed by personal income taxes (19.7 per cent) and indirect taxes (12.5 per cent). Regionally, assuming a per capita distribution of federal revenues, British Columbia experiences the largest combined federal and provincial impact (34.8 per cent), followed by Ontario (24.3 per cent), Alberta (18.4 per cent), and Quebec (13.8 per cent).

Impacts of Higher Netbacks for Producers

In addition to the economic and fiscal impacts associated with building and operating the pipeline the TMEP has the potential to improve the price Canadian oil producers receive for their product. At a minimum, shippers on the TMEP will have access to tidewater, allowing them the ability to attract world prices for their product, rather than North America prices. However, the market study completed by IHS

Global Canada Limited (the IHS study) found that the TMEP and other planned pipeline expansion projects will alleviate the glut of oil flowing to the hub at Cushing, Oklahoma, which is expected to raise prices for all heavy oil producers in Western Canada.

As indicated in the IHS study, producers of conventional heavy oil and bitumen from the oil sands will benefit from higher prices, leading to higher revenues and profits. In turn, these businesses may choose to pay higher dividends or reinvest these profits. As well, there will be fiscal implications in terms of higher royalties and corporate profits paid to federal and provincial governments. We estimate these fiscal impacts under the three different production cases developed by IHS, a base case outlook, a high production outlook, and a low production outlook.

In the IHS base case oil company revenues rise by $45.4 billion over the first 20 years of the pipeline's operations as a result of higher netbacks that can be attributed to the market access provided by the TMEP. This generates total fiscal benefits of $14.7 billion. The federal corporate income tax effects account for $6.1 billion of these effects. The combined royalty and corporate income tax effect for Alberta is $8.2 billion, and for Saskatchewan it is $454 million. The cumulative fiscal effect ranges between $9.2 billion in the high production case and $13.8 billion in the low production case.

Summary

Table 1 summarizes the economic and fiscal impacts associated with the TMEP using the minimum operating impacts and the base case for assessing the impact of higher netbacks. Between 2012 and 2037, the Project is expected to generate 108,310 person-years of employment. As well, the Project will produce $18.5 billion of fiscal benefits over the same period.

Table 1. Summary of the Economic and Fiscal Impacts of the TMEP (cumulative effects, 2012-2037)

	Atlantic Canada	Quebec	Ontario	Other Prairies	Alberta	British Columbia	Territories	Canada
	Using Minimum Operational Effects and the Base Case for Higher Netbacks							
Employment effects (person-years)	**617**	**3,372**	**11,004**	**2,124**	**24,926**	**66,132**	**135**	**108,310**
Project development	289	1,402	4,659	1,099	14,632	35,864	92	58,037
Project operations	327	1,970	6,345	1,025	10,293	30,269	43	50,273
GDP effects (millions of 2012$)	**46.0**	**285.8**	**951.5**	**185.5**	**5,360.5**	**11,329.2**	**15.7**	**18,174.2**
Project development	21.7	120.1	408.6	98.5	1,402.4	2,789.1	11.2	4,851.7
Project operations	24.3	165.6	542.9	87.0	3,958.1	8,540.2	4.5	13,322.5
Fiscal Impact (millions of 2012$)	**564.0**	**1,920.1**	**3,277.7**	**1,030.5**	**9,577.3**	**2,086.5**	**26.6**	**18,482.7**
Project development	48.2	166.2	306.6	57.5	239.1	394.3	2.2	1,214.1
Project operations	104.0	352.1	620.1	111.1	469.3	887.3	4.7	2,548.6
Higher netbacks	411.8	1401.8	2,351.0	861.9	8,868.9	804.9	19.7	14,720.0

Source: The Conference Board of Canada.

Beyond these economic and fiscal benefits, the TMEP will also provide important strategic benefits. In particular, by allowing significant volumes of Canadian oil to reach tidewater Canadian production will no longer be landlocked inside the stagnant North American market. Many producers would now have access to growing markets in Asia. Ultimately, the TMEP is a means for Canada to maximize the value it receives for its non-renewable oil resources.

Chapter 1: Introduction

Oil is a global commodity, with a well established transportation infrastructure. As a result, global benchmark prices are usually nearly identical to one another once adjustments for quality and transportation costs are taken into account. However, this has not been the case in recent years, with North American benchmark prices lagging considerably behind their global peers.[3] This situation has had significant negative economic and fiscal consequences for Canada, particularly in its oil producing regions.

In response, there has been growing interest in developing new oil pipeline infrastructure in North America. There are currently four major pipeline projects under consideration that would carry oil away from Western Canada if completed. One of these is the Trans Mountain Expansion Project (TMEP or the Project), which would nearly triple the capacity of the existing pipeline that runs from Edmonton, Alberta to Burnaby, British Columbia.

The objective of this report is to assess the economic and fiscal impacts associated with the proposed TMEP. (See text box "Trans Mountain Expansion Project Description.") As part of this process, we examine the potential impacts in multiple ways, including the following:

- The impacts associated with the initial required investments to build the pipeline and related infrastructure.
- The impacts associated with operating the pipeline once it is up and running.
- The impacts associated with higher netbacks to oil producers that are expected to result from smaller price differentials between Canadian and international oil price benchmarks.

The results of this analysis allow for a clearer understanding of the economic and fiscal impacts of the pipeline itself, as well as the potential implications for Canada's governments and the oil extraction industry. We discuss the results at both the national and the provincial level, with a particular focus on British Columbia and Alberta, since this is where most of the benefits would occur. We also examine how other provinces and the country overall will benefit, with a focus on supply chain and fiscal effects.

[3] Kelly, Steve. *Trans Mountain Expansion Direct Evidence.*

Trans Mountain Expansion Project Description

The Trans Mountain pipeline system commenced operations 60 years ago and now transports a range of crude oil and petroleum products from western Canada to locations in central and southwestern British Columbia (BC), Washington state and offshore. Trans Mountain currently supplies much of the crude oil and refined products used in BC. Trans Mountain pipeline is operated and maintained by staff located at Trans Mountain's regional and local offices in Alberta (Edmonton, Edson, and Jasper) and BC (Clearwater, Kamloops, Hope, Abbotsford and Burnaby).

The Trans Mountain pipeline system has an operating capacity of approximately 47,690 m^3/d (300,000 b/d) using 24 active pump stations and 40 tanks. The expansion will increase the capacity to 141,500 m^3/d (890,000 b/d).

The proposed expansion will comprise the following:

- Pipeline facilities that complete a twinning (or "looping") of the pipeline in Alberta and BC with about 987 km of new buried pipeline.
- New and modified facilities, including pump stations and tanks.
- A total of three new berths at the Westridge Marine Terminal in Burnaby, BC each capable of handling Aframax tanker size.

Source: Trans Mountain.

Chapter 2: Economic Impacts Associated With the Development of the Trans Mountain Expansion Project

In terms of economic effects, all projects go through two distinct phases. The first is the development phase, when a project is planned, construction activity takes place, and equipment is purchased and installed. The second phase consists of the period over which a project is operational. This includes the annual expenditures on things like labour, facilities maintenance, and other inputs over the lifetime of a project. This chapter considers the economic impacts of developing the TMEP, while the next chapter considers the economic impacts of TMEP operations once the Project is finished.

In this report we quantify four economic effects associated with the development and operations of the TMEP, including the following:

1) **Direct Effects.** These are the economic effects directly associated with the development and operation of the TMEP. During the development phase, most of the direct effects occur in the construction industry, and during the operational phase all of the effects occur in the oil pipeline industry.
2) **Indirect Effects.** The indirect or supply chain effects measure the economic effects associated with the use of intermediate inputs or other support services that will be used to either build the pipeline or maintain it once it is operational.
3) **Induced Effects.** The induced effects occur when the wages that employees earn from the direct and supply chain effects are spent. As such, the economic impacts associated with induced effects generally occur in consumer oriented industries, such as retail.
4) **Fiscal Effects.** Finally, we measure the fiscal impact associated with the other three economic effects, at both the federal and the provincial level.

In order to conduct this analysis, we use both Statistics Canada's interprovincial Input-Output (I/O) model and the Conference Board of Canada's proprietary forecasting models. The direct, indirect, and induced gross domestic product (GDP) and employment impacts associated with the construction and operation of the TMEP were generated using Statistics Canada's I/O model, which allows for detailed supply chain analysis for nearly 300 different industries by province. For a more detailed explanation of I/O models see Appendix C. The fiscal effects were estimated by the Conference Board of Canada. The revenue and cost estimates associated with the construction and operation of the TMEP used to conduct the analysis were prepared by Trans Mountain Pipeline.

2.1 Direct Effects

If approved, the TMEP is expected to cost approximately $5.5 billion, with the expenditures taking place over a seven-year period. Adjusted for price increases, that is equivalent to $4.9 billion in 2012 dollars. Some of these expenditures have already occurred. Parts of the Project, such as planning and regulatory application fillings have already begun, and thus Project Development is expected to cover the 2012 and 2018 period. However, the bulk of the spending activity is expected to take place in 2016 and 2017, when construction activity peaks. (See Table 2.)

Table 2. Expenditure Assumptions Associated With the Development of the TMEP (millions of $)

Year	Nominal $	2012 $	2012 $ Excluding financing costs
2012	34.2	34.2	33.4
2013	55.7	55.0	52.0
2014	93.7	90.3	83.8
2015	273.0	251.7	239.2
2016	2,547.2	2,269.9	2,194.4
2017	2,451.8	2,121.0	1,930.4
2018	49.8	41.7	41.7
Total	**5,505.3**	**4,863.6**	**4,575.0**

Source: Trans Mountain Pipeline.

For the purposes of the analysis, we use the price adjusted figure to conduct the analysis. This is because price inflation does not add to the economic value or jobs that would be supported by the Project. As well, we exclude the estimated financing costs associated with the Project. This is because the economic impacts of the financing costs could be quite small depending on how and where the money is raised. For example, if the project is financed through internal cash flows, or through money raised in foreign markets the impacts on the Canadian financial services sector would be minimal. The end result is that we assess the economic impacts of $4.6 billion of expenditures in 2012 dollars.[4]

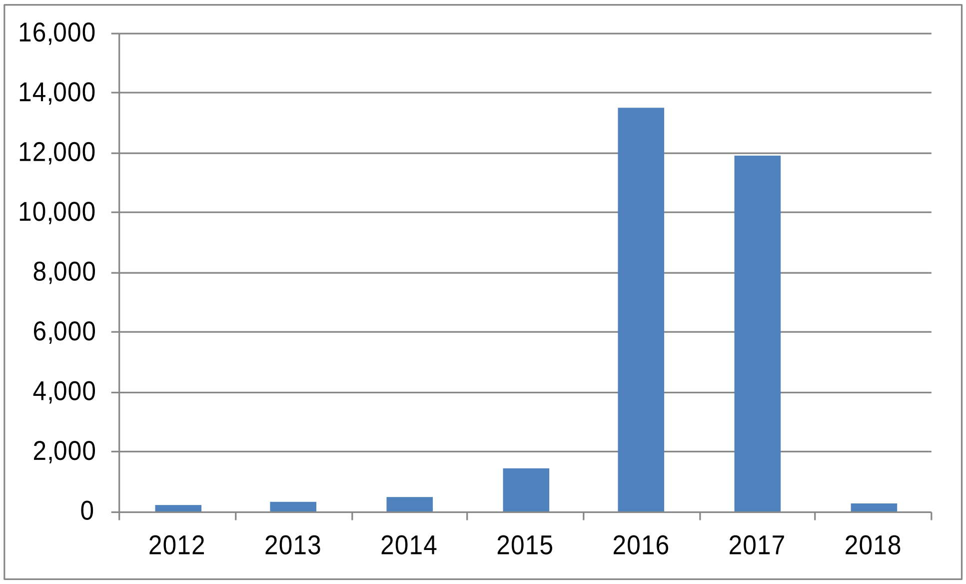
Although only 63.6 per cent of the pipeline's length will be in British Columbia, 69.5 per cent of the expenditures would take place there ($3.2 billion), with the remainder occurring in Alberta ($1.4 billion). To put that into perspective, this is equivalent to 8.7 per cent and 1.9 per cent respectively of total construction expenditures in British Columbia and Alberta in 2011.[5] Factors affecting the regional mix of spending include the terrain that the pipeline covers, the fact that portions of the new pipeline will consist of reactivated existing pipe, and the need to build new port facilities at the Westridge Marine Terminal in British Columbia.

These expenditures will have a direct impact in both provinces. In terms of employment, the development of the pipeline is expected to support 28,202 person-years of employment, with 20,675 of these jobs occurring in British Columbia and the rest occurring in Alberta.[6] The timing of these employment impacts will coincide with changes in annual expenditures on the Project. For example, in 2012, the direct employment impacts were estimated to be 206 people. But at the peak of construction in 2016, the employment supported by the Project will rise to 13,527 people. (See Chart 1.) At their

[4] Unless otherwise noted, all subsequent dollar figures in the report are stated in 2012 dollars.
[5] Based on data from Statistics Canada CANSIM table 029-0024.
[6] A person-year of employment is the amount of work that one person would normally conduct in a year. It is an average figure for each industry and takes into account the fact that some workers are part time.

peak, the provincial employment effects will be equivalent to 4.3 per cent and 1.4 per cent of British Columbia's and Alberta's respective 2016 construction employment.[7]

Chart 1. Employment Impacts Associated With the Construction of the TMEP (number of employees)



Source: The Conference Board of Canada.

In terms of GDP, we expect that the TMEP will directly generate cumulative GDP effects of $2.2 billion over the development period of the Project. Thus for every $100 dollars spent on the Project, $47 dollars in GDP will be generated. This means that 47 cents of every dollar spent goes to wages and profits, primarily in the construction industry, while the other 53 cents is spent on material inputs. The regional and temporal GDP impacts are similar to those noted for employment, with British Columbia accounting for 70 per cent of the total and the rest occurring in Alberta. The GDP effects peak in 2016 and 2017, when construction activity is at its peak.

2.2 Indirect Effects

In addition to the direct effects discussed above, the TMEP will also generate indirect or supply chain effects, and the I/O model captures these effects. Development of the Project will support another 14,055 person-years of employment indirectly. Thus, the combined direct and indirect employment effects of the TMEP are 42,257 person-years of employment. This is equivalent to 9,236 person-years of employment being supported for every $1 billion dollars of investment.

Another way to look at the indirect effects is in terms of multipliers; i.e. how many jobs or dollars of GDP are indirectly generated relative to the direct effects. For example, for every two jobs directly associated with the TMEP, it supports another job indirectly among its suppliers. The GDP multiplier is somewhat larger, with $0.58 of indirect GDP being supported by each direct dollar. The key reason for the higher

[7] The Conference Board of Canada. *Provincial Economic Outlook: Spring 2013.*

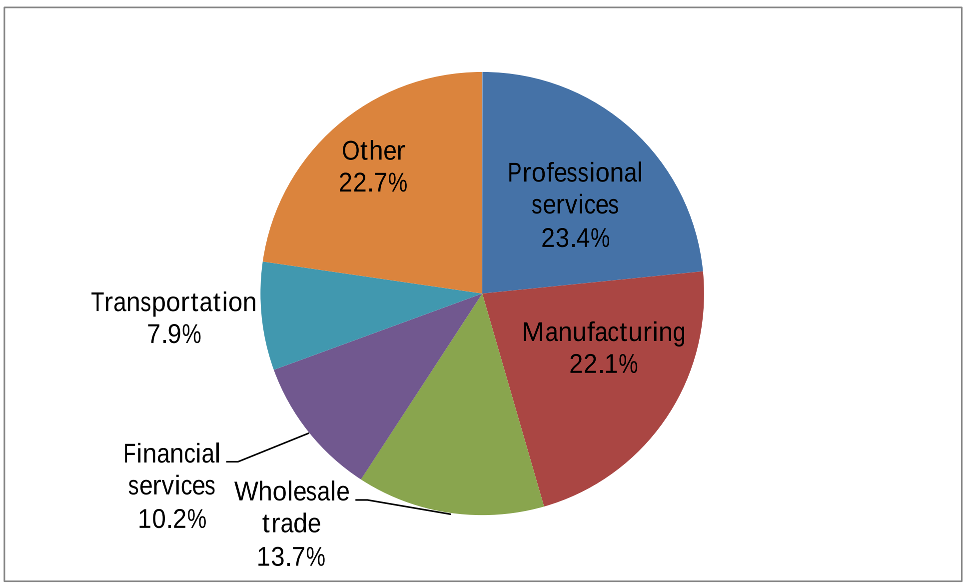
GDP multiplier is that most of the sectors where the largest indirect effects occur have a high level of GDP per employee.

The indirect effects are felt across a wide range of industries that are part of the supply chain that would be linked to the TMEP. The supply chain effects include both those that would directly supply the Project, as well as second and third order effects on suppliers who are farther down the supply chain. Although the majority of the indirect effects occur in British Columbia and Alberta, all of the other provinces experience some benefits. More than one quarter of the indirect employment effects occur in other provinces, with Ontario experiencing the largest benefit. The rest of this section describes how different industries and different regions of the country benefit from the supply chain effects that result from the construction of the TMEP.

2.2.1 Indirect Effects by Sector

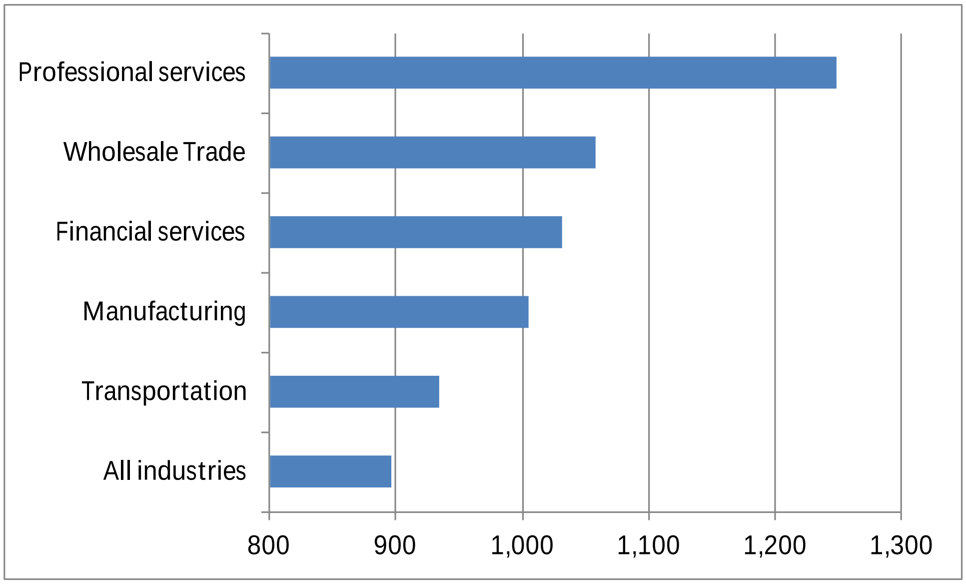
Beyond the number of jobs that would be indirectly supported by the construction of the TMEP, it is also important to examine the types of jobs. The indirect effects are largely confined to five broad sectors. In order of size, they include professional services, manufacturing, wholesale trade, financial services, and transportation. (See Chart 2.) It is worth noting that all of these sectors pay above-average wages. Even the lowest-paying sector, transportation and warehousing, has average weekly earnings that are 5 per cent above the average for all industries. (See Chart 3.) As such, the direct and indirect effects of the TMEP support a substantial number of high paying jobs.

Chart 2. Key Sectors That Experience Supply Chain Effects
(share of supply chain employment effects)



Source: The Conference Board of Canada.

Chart 3. All of the Sectors Most Affected by the TMEP's Development Pay Above Average Wages (average weekly earnings in 2012, including overtime, $)



Source: Statistics Canada CANSIM table 281-0027.

2.2.1.1 Professional Services

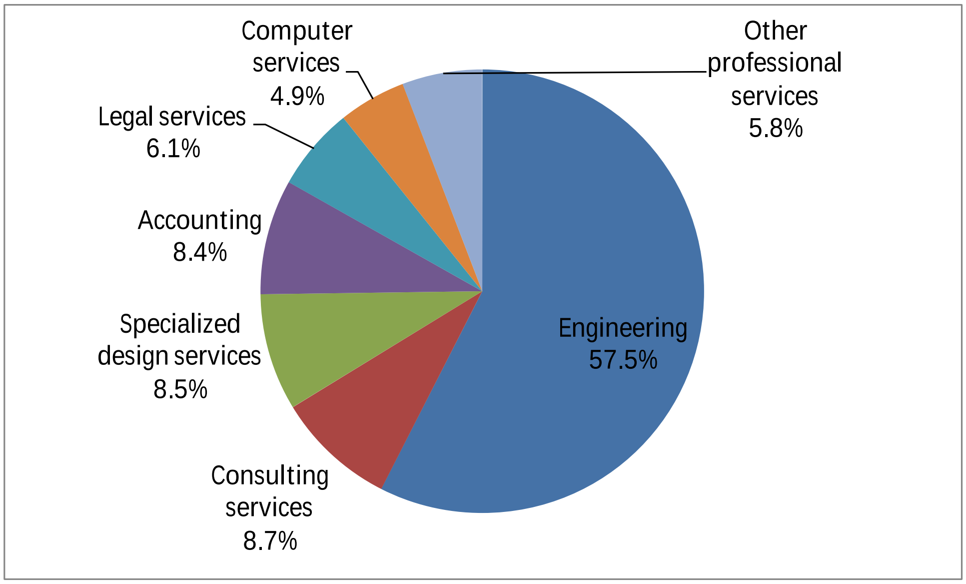
The professional services sector encompasses a wide area of activities in which human capital is the major input. These businesses essentially sell the knowledge and skills of their employees. With 3,287 person-years of employment in the sector being supported by the TMEP, or 719 for every $1 billion of inflation-adjusted investment, the largest supply-chain effects accrue to this sector.

The single largest effects within this sector occur in the engineering services industry, with 1,890 person years of employment, or 413 for every $1 billion in investment, being supported by the TMEP. (See Chart 4.) Engineering is the largest activity within this industry, but activities like geophysical surveying and mapping would also likely be an important component of the supply-chain benefits. The benefits for the engineering industry are so large that they account for 13.4 per cent of the total supply chain effects associated with development of the TMEP.

Other industries within the professional services sector would also realize employment benefits. For example, every billion dollars in investment generates 63 person-years of employment in consulting services. Specialized design services (61 person-years) and accounting services (60 person-years) also benefit. A variety of other professional service industries – everything from computer services, to legal services, to advertising and public relations – are also positively affected.

Regionally, the largest impact is in British Columbia, where nearly two-thirds of the employment benefits will occur, while another 25 per cent would be associated with Alberta. Still, substantial benefits do accrue to other Canadian provinces. For every $1 billion in investment spending connected to the TMEP, 83 person-years of professional services employment will be supported outside of the two provinces through which the pipeline would traverse.

Chart 4. Engineering Accounts for Most of the Supply Chain Effects in the Professional Service Sector (share of supply chain employment effects in professional services)



Source: The Conference Board of Canada.

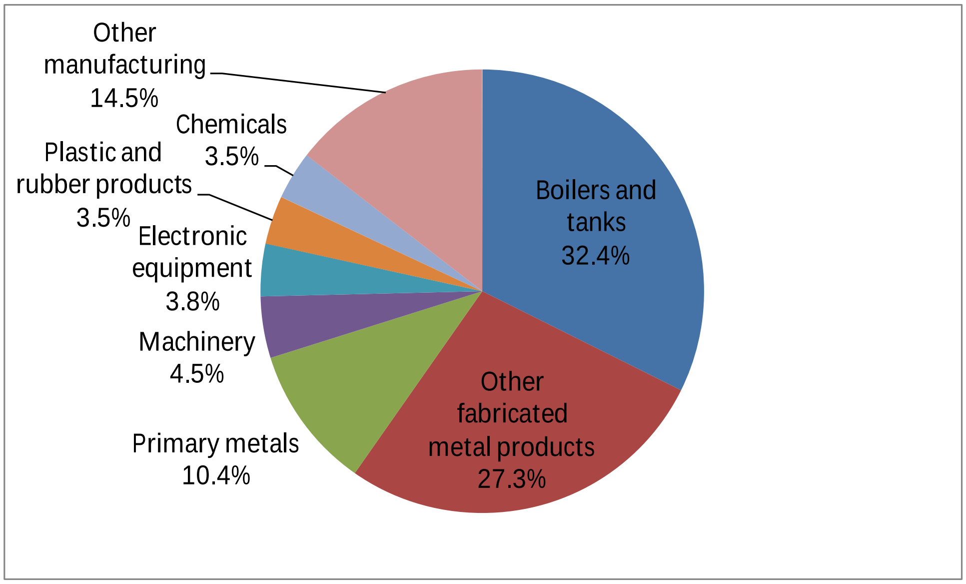
Most of the professional service jobs supported outside of Alberta and British Columbia (65 per cent) will be in Ontario; the province will experience a disproportionate benefit in several industries. For example, even though Ontario accounts for only 8 per cent of the total employment effects in professional services, it accounts for 35 per cent of the effects in the computer services industry—a higher share than either British Columbia or Alberta. It will also receive a relatively high share of the effects in the advertising and public relations (29 per cent), and scientific research and development services (27 per cent) industries. In aggregate, 96 per cent of the expected gains in professional services will accrue to British Columbia, Alberta, or Ontario.

2.2.1.2 Manufacturing

Manufacturing is another sector that experiences indirect effects associated with the development of the TMEP, accounting for 22.1 per cent of the employment benefits. This is equivalent to 3,108 person-years of employment, or 679 for every $1 billion of investment.

Key industries within the manufacturing sector that realize the greatest benefits include makers of boilers and tanks, where 32 per cent of the manufacturing related employment effects will be apparent. (See Chart 5.) Other types of fabricated metal products, such as architectural metal products, and machine shops, as well as primary metals (in particular steel producers) are where the largest effects are apparent. For example, the economic activity associated with the producers of steel pipe (a major input into the Project), is captured in the steel products industry. However, a wide variety of other manufacturing industries, such as machinery, electronic equipment, plastic and rubber products, and chemicals also benefit.

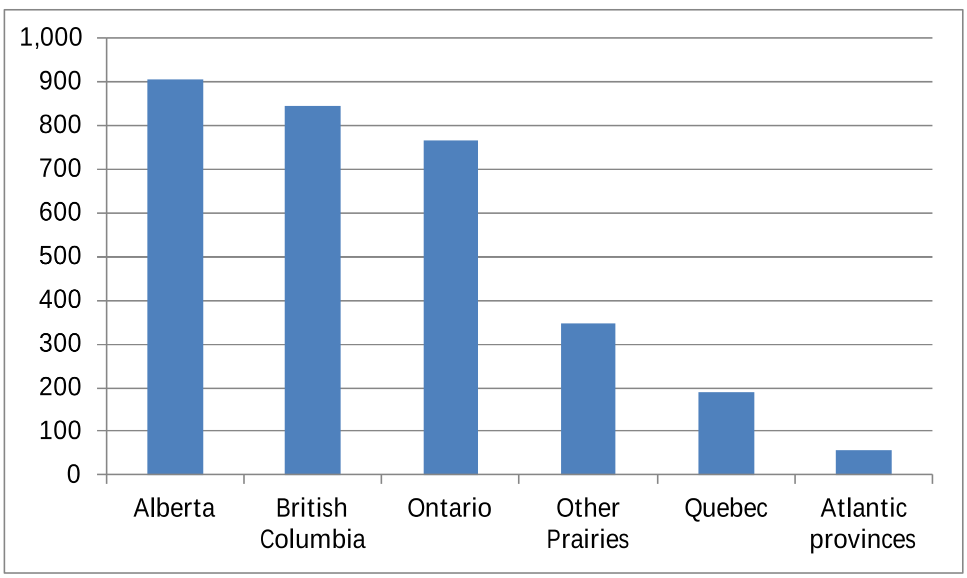
Chart 5. Most of the Manufacturing Impacts Occur Among Producers of Fabricated Metal Products (share of supply chain employment effects in manufacturing)



Source: The Conference Board of Canada.

Compared to the professional services industries, the regional impacts within the manufacturing sector are more diverse. Just 56 per cent of the associated jobs in the sector accrue to Alberta or British Columbia, compared to 88 per cent in professional services. Among the sectors most affected by the TMEP, manufacturing is where the largest benefits occur outside of Alberta and British Columbia. For every $1 billion in inflation-adjusted investment in the TMEP, 297 new person-years of employment are supported outside of Alberta or British Columbia. (See Chart 6.)

Chart 6. The Manufacturing Employment Effects Are Widely Dispersed Across Regions (person years of employment)



Source: The Conference Board of Canada.

One-quarter of all manufacturing-related jobs supported by the TMEP would originate in Ontario, not at all surprising given that the majority of Canada's manufacturing sector is located in that province. In some industries like iron and steel mills, more benefits accrue to Ontario (60 per cent) than to Alberta and British Columbia combined. The province also does well in architectural and structural metals, steel products, and plastics. Nearly 20 percent of manufacturing jobs will be found outside of Alberta, British Columbia and Ontario. Of these, nearly half will occur in Manitoba and Saskatchewan. The remaining manufacturing employment effects are concentrated in Quebec, where 190 person-years of employment can be expected.

2.2.1.3 Wholesale Trade

The wholesaling process is an intermediate step in the distribution of goods. Firms operating in this sector are organized to sell goods in large quantities to other firms, without transformation, and to render services incidental to the sale of merchandise in general. A total of 1,919 person-years of employment would be supported in this sector as a result of the development of the TMEP, which equates to 419 person-years of employment for every $1 billion invested.

Most of the jobs in the wholesale trade sector would be concentrated in two industries; building materials suppliers, and machinery and equipment suppliers. Combined, these two industries account for 73 per cent of the indirect benefits that are expected to accrue to the wholesale trade sector. This essentially reflects the role of wholesalers as middlemen, supplying the equipment and materiel needed to undertake the Project. The only other specific activity worth noting are wholesalers of electronic products, which account for another 10 per cent of the estimated employment effects.

Wholesaling activities are concentrated in the two provinces through which the pipeline would pass. Specifically, British Columbia would realize 1,016 (53 per cent) person-years of employment and Alberta would see 461 person-years of employment (24 per cent). However, for every $1 billion spent on the proposed pipeline, 97 person-years of employment in wholesaling are supported outside those two provinces, and as with all other industries, the majority of them should be expected in Ontario, but about 7 per cent of them could be expected elsewhere.

2.2.1.4 Financial Services

The financial services sector covers a diverse array of activities, including banking, insurance, and investment-related services. As well, activities like the rental and leasing of machinery, equipment, and real estate are included. In total, the indirect benefits associated with this sector include 1,439 person-years of employment. This is equivalent to 315 person-years of employment per $1 billion invested in the TMEP, and 10.2 per cent of the total indirect employment effects.

The aggregate benefits are concentrated in three main industries, including rental and leasing activities, banking, and investment services. In the case of rental and leasing activity, more than 95 per cent of the employment effects occur in either Alberta or British Columbia – a logical outcome given that rental and leasing of machinery and equipment is normally a local activity. However, both the banking and financial investment services industries experience above-average effects outside of Alberta or British Columbia.

For example, 47 per cent of all the indirect benefits in the banking industry occur elsewhere in Canada—as these services are easily tradable they tend to be less location specific.

In aggregate, for every $1 billion invested in the TMEP, 91 person-years of employment in the financial services sector would be supported elsewhere in Canada and more than two-thirds of this would be created in Ontario. Given that most of Canada's largest banks and insurance companies are headquartered in Ontario, it is not surprising that 30 per cent of the employment effects in banking, holding companies, financial investment services, and insurance carriers would be generated there.

2.2.1.5 Transportation

The other sector to derive substantial indirect benefits as a result of the development of the TMEP is transportation. Establishments in the sector use transportation equipment as a productive asset to provide transportation of passengers or cargo, as well as the warehousing and storage of goods. The major modes of transportation include trucking, ground passenger, rail, water, air, and pipelines. Couriers and postal service are also included.

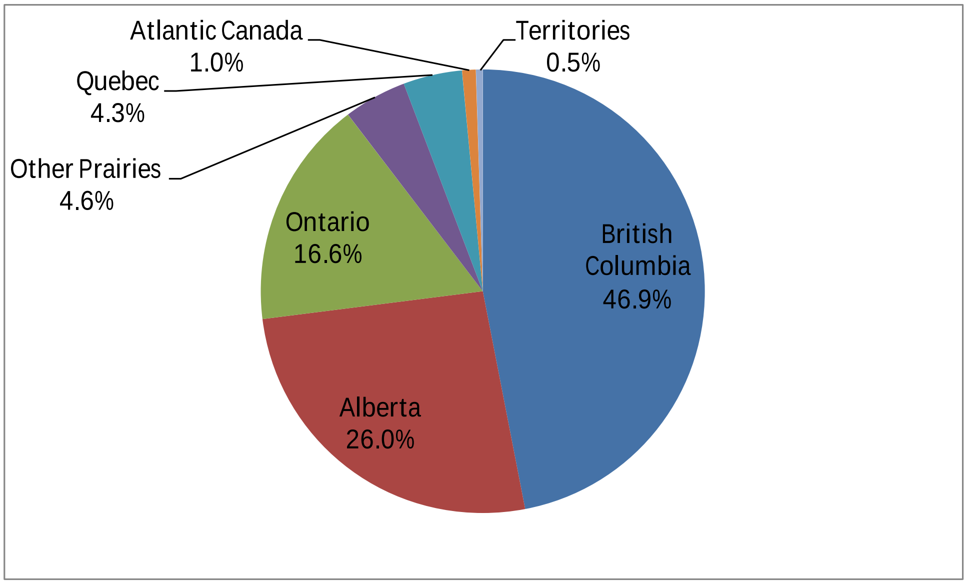
The proposed TMEP, in aggregate, would support 1,116 person-years of employment in the transportation sector, equivalent to 244 for every $1 billion of investment. More than 60 per cent of these will be either in the trucking industry, or activities that support the trucking industry. This reflects the fact that there are logistical challenges involved with getting sufficient materials to the construction sites, given that the actual pipeline will span more than 1,000 km. Rail transportation will also garner 12 per cent of the estimated employment effects, reflecting the need to move some of the material inputs long distances across the country.

Again, British Columbia derives the largest benefits associated with the transportation sector, as 36 per cent of the employment effects will be found there, the wide majority of them in trucking. The story is similar for Alberta, which will garner 29 per cent of the benefits, most of them in trucking. Still, 394 person-years of employment will be supported in other Canadian provinces – or 86 per $1 billion invested. Truck transportation is the dominant industry within the sector across the country, accounting for 63 per cent of the transportation jobs in Ontario, 70 per cent in Quebec, and 62 per cent of the jobs in the Prairie Provinces.

2.2.2 Indirect Effects by Region

Although the majority of indirect impacts will occur in British Columbia and Alberta, every region in the country will derive some economic benefit from the development of the TMEP. We estimate that 27.1 per cent of the indirect employment impacts, or 3,796 person years of employment will occur in other regions of the country. (See Chart 7.) As well, the mix of industries affected in each region can be very different. For example, manufacturing accounts for more than half of the employment effects in the Prairie Provinces, but only 12.8 per cent of the effects in British Columbia.

Chart 7. Indirect Employment Effects Supported by the Construction of the TMEP by Region (share of construction related indirect employment effects)



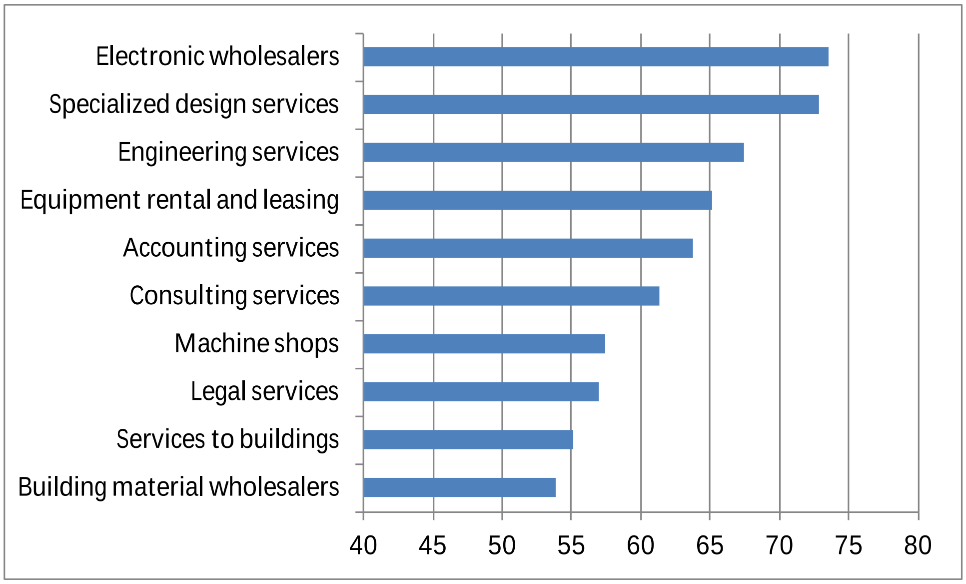
Source: The Conference Board of Canada.

2.2.2.1 British Columbia

British Columbia experiences the largest supply chain effects associated with the development of the TMEP. In total, 6,599 person-years of employment will be supported by the Project, equivalent to 46.9 per cent of the total supply chain effects. Despite the fact that nearly half of the supply chain effects will occur in British Columbia, the mix of sectors affected in the province is somewhat different than in other provinces. Professional services experience the largest benefits by far, accounting for nearly one-third of the total, followed by wholesale trade, and then manufacturing.

It is interesting to note the industries that stand out in British Columbia, in terms of those that experience effects that are both substantial in size and account for an outsized share of the national impacts. For example, 67 per cent of the national impacts in the engineering industry occur in British Columbia, accounting for a total of 1,275 person-years of employment. (See Chart 8.) Engineering accounts for the largest impact by far in British Columbia. However other industries with noticeable effects include wholesalers of building materials, specialized design services, and equipment rentals and leasing.

Chart 8. Key Industries that Experience Outsized Effects in British Columbia
(share of national supply chain employment effects for select industries, per cent)



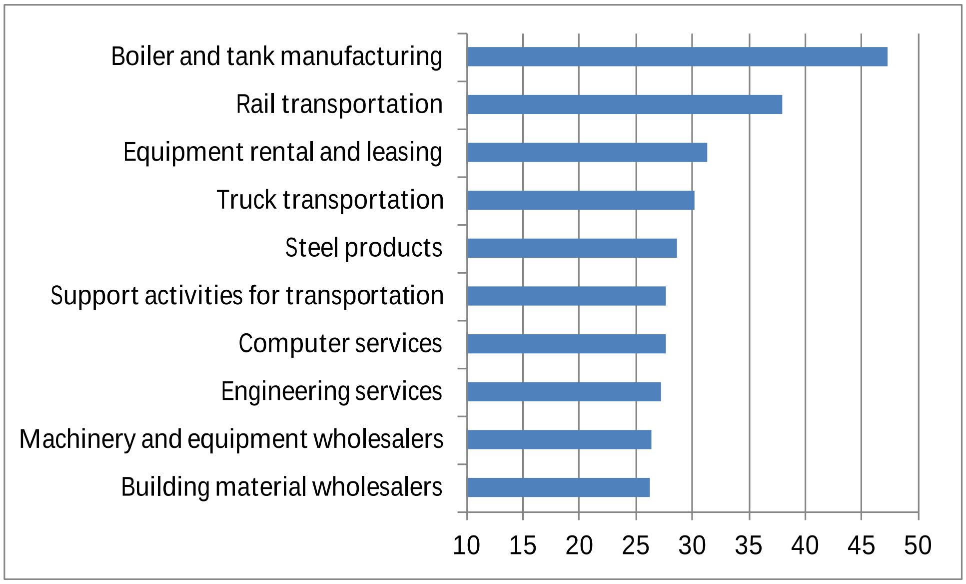
Source: The Conference Board of Canada.

2.2.2.2 Alberta

Much of the remaining indirect employment impacts accrue to Alberta. In total, the development of the TMEP is expected to support 3,660 person-years of employment in Alberta, which is equivalent to 26 per cent of the total national effects. The sector that will experience the single biggest impact in Alberta is manufacturing. This is followed by professional services, and then wholesale trade. Alberta stands out by accounting for an outsized share of the effects in the manufacturing and transportation sectors.

As is the case in British Columbia, engineering services are where the largest employment impacts occur in Alberta. (See Chart 9.) However, where Alberta stands out is in the manufacture of boilers and tanks. Nearly half of the employment effects in this industry occur in Alberta. Other industries where Alberta stands out include truck transportation, wholesalers, and rental and leasing of equipment.

Chart 9. Key Industries that Experience Outsized Effects in Alberta
(share of national supply chain employment effects for select industries, per cent)

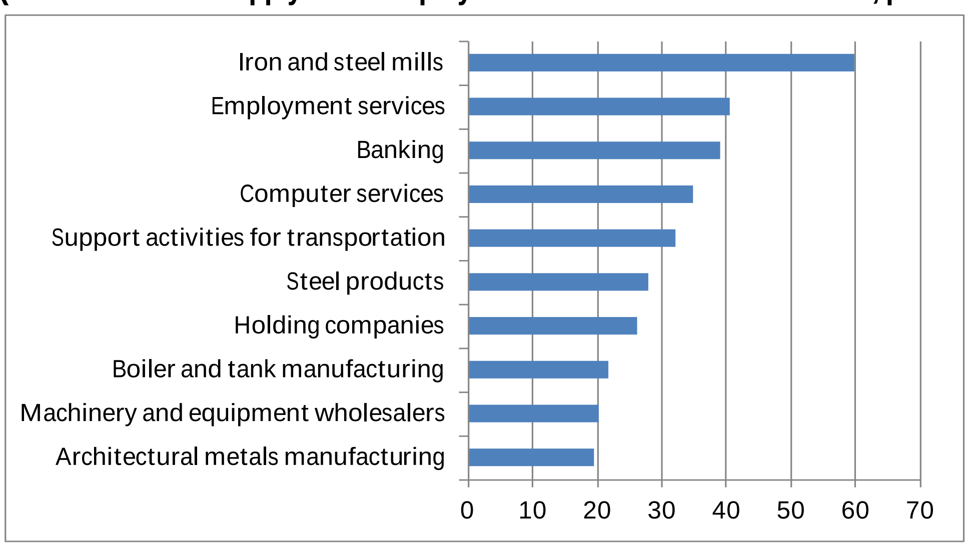


Source: The Conference Board of Canada.

2.2.2.3 Ontario

Outside of Alberta and British Columbia, Ontario experiences the largest supply chain impacts associated with the development of the TMEP. A total of 2,340 person-years of employment will be supported in Ontario, equivalent to 16.6 per cent of the total. Manufacturing and financial services are the two key areas where Ontario stands out. More specifically, industries where Ontario experiences an outsized share of the employment effects include boiler and tank manufacturing, machinery and equipment wholesalers, banking and support activities for transportation. (See Chart 10.)

Chart 10. Key Industries that Experience Outsized Effects in Ontario
(share of national supply chain employment effects for select industries, per cent)

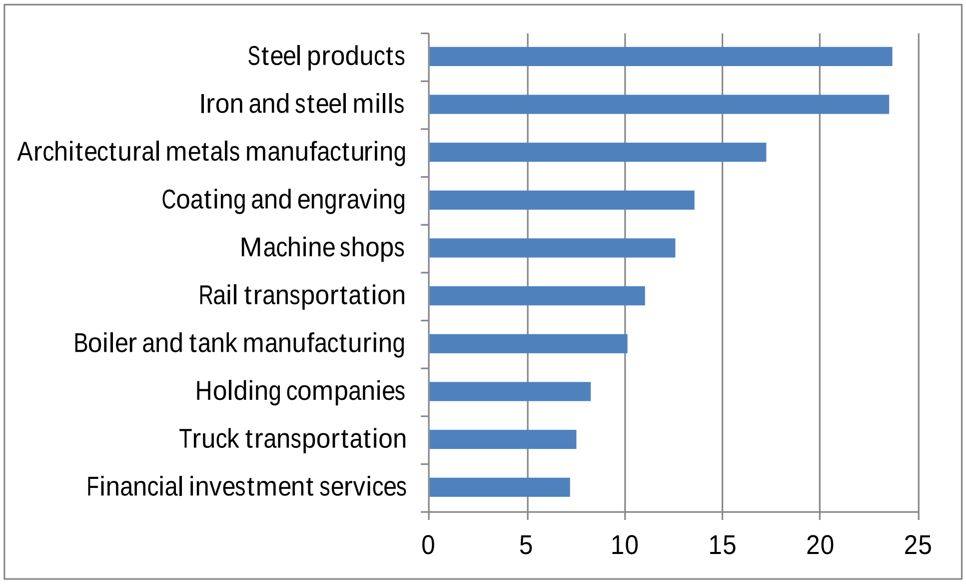


Source: The Conference Board of Canada.

2.2.2.4 Other Prairies

Beyond British Columbia, Alberta, and Ontario, the employment effects associated with the development of the TMEP become smaller. Manitoba and Saskatchewan combined will see 645 person-years of employment being supported by the Project, with the effects split evenly between the two provinces. As a result, the other Prairies region will account for 4.6 per cent of the supply chain effects. The key areas where the region stands out include manufacturing and transportation. We estimate that 53.9 per cent of the employment effects in Manitoba and Saskatchewan are found in the manufacturing sector. Key types of manufactured products include boilers and tanks, architectural metals and steel products. (See Chart 11.) In the I/O model results, a good portion of the pipe used to build the pipeline will be sourced from Saskatchewan.

Chart 11. Key Industries that Experience Outsized Effects in the Other Prairies Region (share of national supply chain employment effects for select industries, per cent)

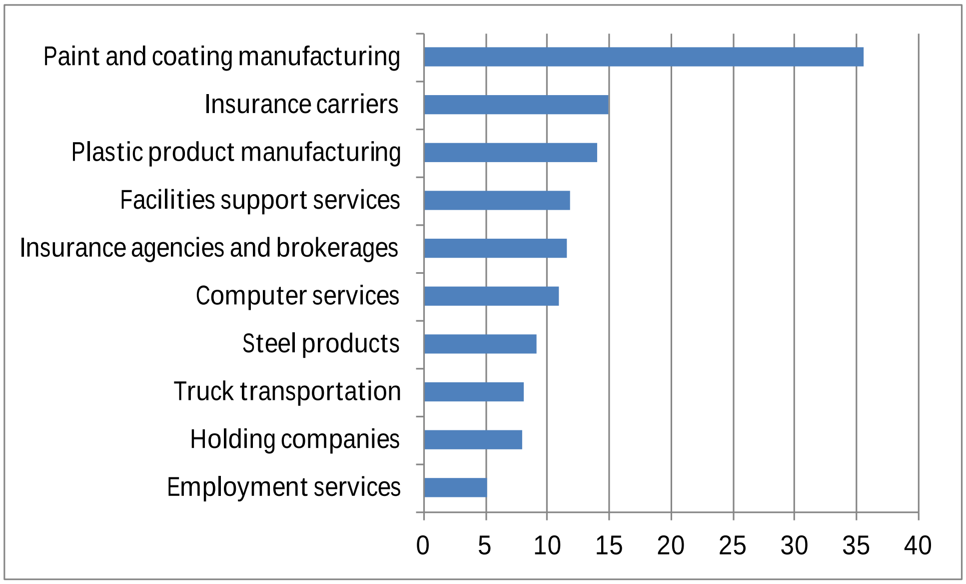


Source: The Conference Board of Canada.

2.2.2.5 Quebec

The employment impacts in Quebec are modestly smaller than those experienced in the other Prairies region. A total of 601 person-years of employment will be supported in Quebec as a result of the development of the TMEP, equivalent to 4.3 per cent of the total. Areas where the effects in Quebec stand out include manufacturing and transportation. In particular, truck transportation, manufacturing of paints and coatings, and computer services will all experience outsized effects. (See Chart 12.)

Chart 12. Key Industries that Experience Outsized Effects in Quebec
(share of national supply chain employment effects for select industries, per cent)

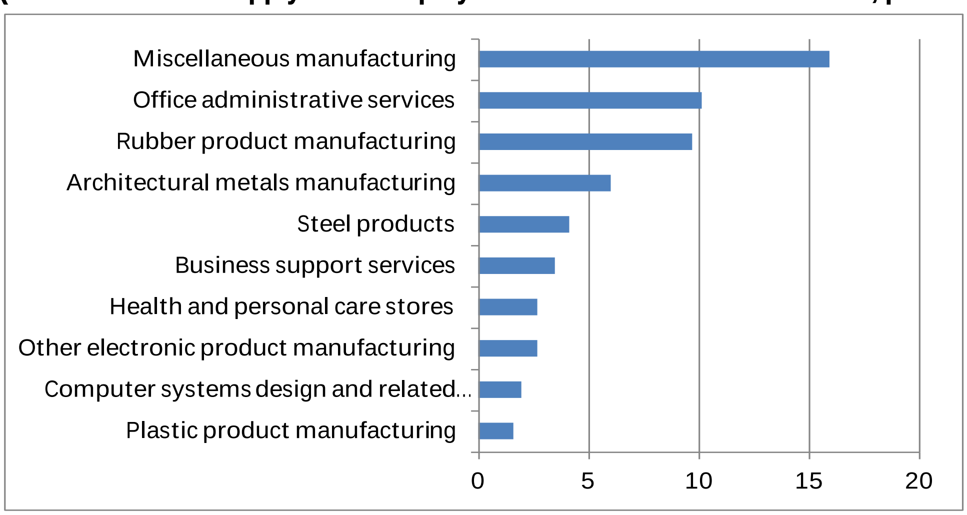


Source: The Conference Board of Canada.

2.2.2.6 Atlantic Canada

The Atlantic Provinces experience the smallest employment effects as a result of the development of the TMEP. Their smaller size and physical distance from where the TMEP will be built are both factors limiting the benefits they will experience. Only 142 person-years of employment will be supported in the region, equivalent to 1 per cent of the total impact. Most of those effects will occur in Nova Scotia and New Brunswick. The effects in any particular industry are generally quite small, but there are outsized effects in a few industries, such as architectural metals, office administrative services, and miscellaneous manufacturing. (See Chart 13.)

Chart 13. Key Industries that Experience Outsized Effects in Atlantic Canada
(share of national supply chain employment effects for select industries, per cent)



Source: The Conference Board of Canada.

2.3 Induced Effects

Additional benefits beyond those described above will arise as a result of the development of the TMEP. For example, the person-years of employment supported both directly and indirectly by development of the pipeline generates wages that, when spent, sustain additional employment across the country. This income effect is commonly referred to as "induced effects" in the economic literature.

Induced effects lead to additional impacts on GDP, employment, income, and tax revenues and they are felt across a wider range of industries relative to the supply-chain effects described above. And because the direct and indirect jobs created tend to be in high-wage industries, the spin-off effects are substantial. Indeed, the induced impacts associated with developing the TMEP are estimated to be slightly larger, in terms of both GDP and employment, than the indirect benefits.

In total, 15,780 person-years of induced employment would be supported by development of the pipeline – equivalent to 3,450 jobs for every $1 billion in inflation-adjusted investment. These employment impacts are widespread, with 10 different sectors experiencing an impact of at least 500 person-years of employment. When the induced employment impacts are added to the previously discussed direct and indirect employment effects, the development of the TMEP is expected to support 58,037 person-years of employment.

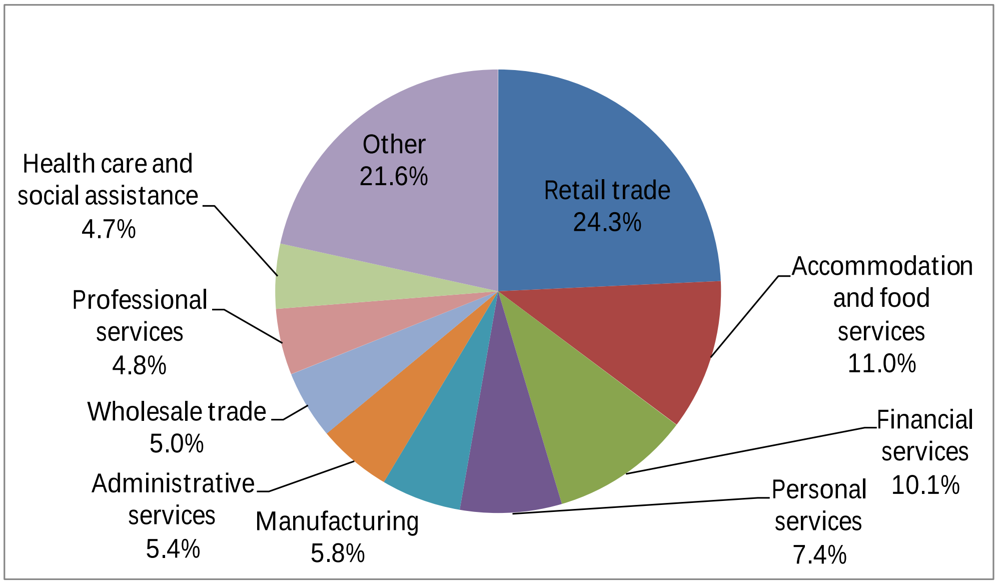
The induced GDP effects are also considerable. For every $1 in GDP directly created as a result of the Project, another $0.66 is supported by the income effects, in addition to $0.58 in supply-chain benefits. Thus, in aggregate, the GDP effects associated with the development of the Project are $4.9 billion ($2.2 billion directly, $1.3 billion indirectly, and $1.4 billion induced). This is equivalent to $1.06 of GDP for each dollar spent on the development of the TMEP.

2.3.1 Induced Effects by Sector

The distribution of the induced employment effects across sectors is largely a reflection of how Canadian consumers spend their money. (See Chart 14.) For example, the largest impact is found in the retail sector, which accounts for 3,831 person-years of employment, or 24.3 per cent of the total. Specifically, the induced effects accruing to the retail sector would support 1,220 person-years of employment in food and beverage establishments, another 445 in clothing and accessories, and 328 in motor vehicles and parts sales. The benefits are extremely varied, with impacts apparent in everything from furniture and home furnishings, to home electronics and appliances, to sporting goods and hobbies.

Accommodations and food services is another consumer oriented sector that experiences sizeable benefits. A total of 1,729 person-years of employment, or11 per cent of the total employment effects occur in this sector. Other major sectors where sizeable employment impacts will occur include financial services (1,589 person-years of employment), personal services (1,168 person-years of employment), and manufacturing (918 person-years of employment). The impacts in the financial services sector reflect people's need for things like chequeing accounts and consumer financing. Personal services includes things like household services (such as maids, nannies, and gardeners), as well as activities like motor vehicle repair, laundry services, and hair salons. Finally the impacts in manufacturing generally occur among makers of consumer goods, such as food and furniture.

Chart 14. The Induced Impacts Affect a Range of Consumer Oriented Sectors (share of induced employment effects by sector, per cent)



Source: The Conference Board of Canada.

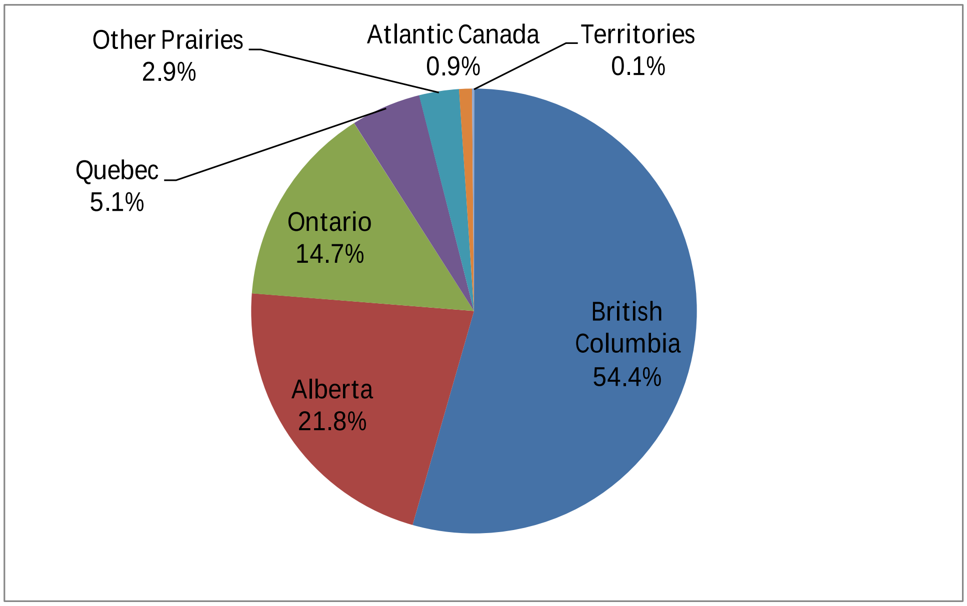
2.3.2 Induced Effects by Region

The regional distribution of the induced effects is fairly concentrated. Some 76 per cent of the total benefits accrue to either British Columbia (8,590 person-years) or Alberta (3,445 person-years). (See Chart 15.) This is not surprising. The majority of the direct and indirect jobs and labour income supported by the Project occur in those provinces, and the residents of those provinces who benefit from the Project will spend most of their income there. The induced impacts across the rest of the provinces largely reflects their shares of the direct and indirect effects.

The sectoral mix of the induced effects is similar across the different regions, since people tend to buy the same sorts of goods and services regardless of where they live. However, because the different regions of the country specialize in making different types of consumer products, there are some variations across the provinces. For example, although Ontario receives 14.7 per cent of the total induced employment effects on an aggregate basis, 24.2 per cent of the benefits in the financial services sector accrue there. Ontario also experiences an outsized share of the effects in the manufacturing sector.

Similarly, Manitoba and Saskatchewan combined can expect just 2.9 per cent of the total induced employment effects, but would garner 16.6 per cent of the agricultural impacts. Essentially the food that people buy as a result of the induced impacts needs to be grown somewhere, and the Prairies will supply some of that food. Quebec stands out in terms of its manufacturing sector. Quebec experiences induced effects of 801 person-years of employment, 5 per cent of the total, but it experiences 15.3 per cent of the employment effects in the manufacturing sector.

Chart 15. The Induced Impacts Primarily Occur in British Columbia and Alberta
(share of induced employment effects by sector, per cent)



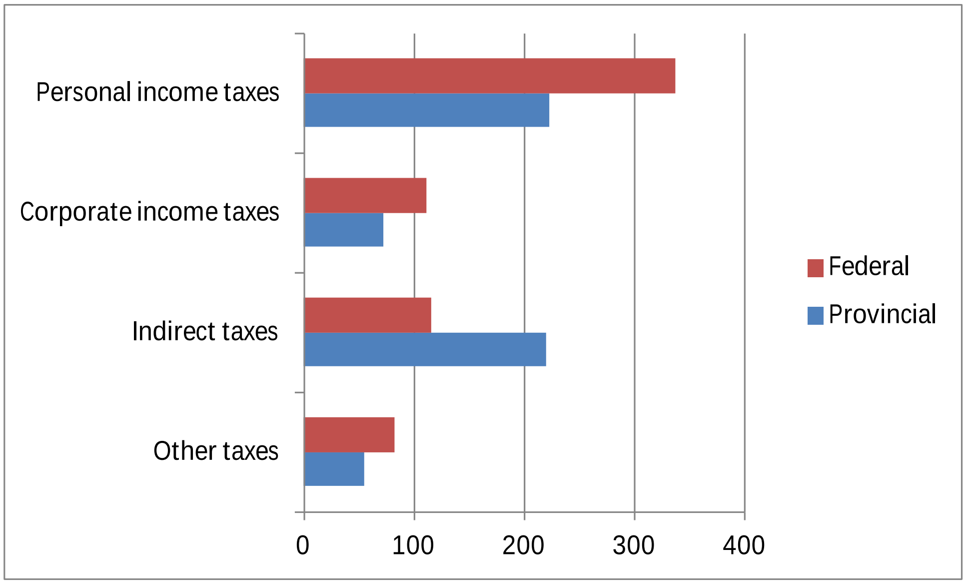
Source: The Conference Board of Canada.

2.4 Fiscal Effects

The direct, supply chain, and induced effects associated with the development of the TMEP also have positive fiscal implications at both the provincial and federal level. The three main types of government revenues that will be affected by the Project include personal income taxes, corporate income taxes, and indirect taxes (such as sales taxes and taxes on fuel). The analysis of the fiscal effects of the project was completed using The Conference Board of Canada's national and provincial forecasting models.

The $4.6 billion in spending associated with the development of the TMEP is expected to generate $1.2 billion in federal and provincial government revenues between 2012 and 2018. This is equivalent to $27 for every $100 of investment. With $3.3 billion in wages and salaries and $1.4 billion in corporate profits being generated by the development of the TMEP, the largest fiscal impacts are found in personal and corporate income taxes. (See Chart 16.)

Chart 16. Personal and Corporate Income Taxes Account for Most of the Fiscal Effects (tax revenues, millions of 2012$)



Source: The Conference Board of Canada.

2.4.1 Federal Impacts

The federal government will experience the largest impact, even larger than that of Alberta and British Columbia combined. In aggregate, the development of the TMEP is expected to generate $645.8 million in federal government revenues, or $14 for every $100 spent on the Project. This is equivalent to 0.3 per cent of total federal government revenues in 2012. Slightly more than half of this will come from higher personal income tax revenues. Other major sources include corporate income taxes (17.2 per cent) and goods and services tax (GST) inflows (14.4 per cent).

Another source of revenues is the $56.4 million generated from higher employment insurance premium receipts. With a total of 58,037 person-years of employment (including the combined direct, supply chain, and induced effects) supported by the development of the TMEP, additional employment insurance premiums will be generated. Since fewer people would be unemployed, government payments of employment insurance would also be reduced, providing an additional benefit not included here.

2.4.2 Provincial Impacts

In aggregate, the TMEP is expected to generate $568.6 million in provincial government revenues, or 12 cents for every dollar spent. This is equivalent to 0.2 per cent of total provincial revenues in 2012. At $222 million, personal income taxes will account for nearly half of the provincial fiscal effects. Indirect taxes (which include sales taxes) and corporate income taxes account for most of the rest of the effects, at $220 million and $73 million, respectively.

In terms of the breakdown by province the largest benefits would accrue to British Columbia, which would receive 54.4 per cent of the total, or $309 million. Alberta would receive most of the rest of the provincial fiscal effects, at $168 million. Ontario ($57 million), Quebec ($17 million), Saskatchewan ($9 million), and Manitoba ($5 million) will experience much more modest fiscal effects. For the Atlantic provinces, the fiscal effects are very small.

If we assume that the federal government revenues would be spent rather than be used to reduce the deficit, the benefits would filter down to all of the provinces through transfers and other program expenditures. Since many of these expenditures are at least partially dependent on the population distribution across provinces, the impact of higher federal revenues will be higher for most provinces than the direct province-specific fiscal effects. For example, assuming a straight per capita distribution of federal revenues, Ontario would garner 39 per cent, or $250 million of the federal fiscal benefits, compared with a direct provincial fiscal impact of $57 million. The exceptions are British Columbia and Alberta, where the direct provincial impact is bigger than the estimated federal transfers.

2.5 Summary

The development of the TMEP is expected to result in $4.6 billion in investment spending, which will have positive economic and fiscal effects. For example, the combined direct, indirect, and induced employment effects will support 58,037 person-years of employment. (See Table 3.) As well, the combined GDP effects of the Project are $4.9 billion, equivalent to $1.06 dollars for every dollar of investment. Finally, this economic activity is expected to support $1.2 billion in federal and provincial government revenues. British Columbia is the largest beneficiary for all of these effects, but considerable effects are apparent in Alberta and Ontario as well. In the rest of the provinces the effects are smaller, but individual industries do experience notable effects in most regions.

Table 3. Summary of the Regional Impacts of Developing the TMEP (cumulative effects, 2012-2018)

	Atlantic Canada	Quebec	Ontario	Other Prairies	Alberta	British Columbia	Territories	Canada
Employment effects (person-years)	**289**	**1,402**	**4,659**	**1,099**	**14,632**	**35,864**	**92**	**58,037**
Direct	0	0	0	0	7,527	20,675	0	28,202
Indirect	142	601	2,340	645	3,660	6,599	69	14,055
Induced	147	801	2,319	454	3,445	8,590	23	15,780
GDP effects (millions of 2012$)	**21.7**	**120.1**	**408.6**	**98.5**	**1,402.4**	**2,789.1**	**11.2**	**4,851.7**
Direct	0.0	0.0	0.0	0.0	650.1	1,518.0	0.0	2,168.1
Indirect	10.8	52.7	207.7	61.4	394.0	514.8	9.0	1,250.5
Induced	10.9	67.4	200.9	37.1	358.3	756.3	2.2	1,433.0
Fiscal Impact (millions of 2012$)	**48.2**	**166.2**	**306.6**	**57.5**	**239.1**	**394.3**	**2.2**	**1,214.1**
Direct Provincial Revenues	4.4	17.1	56.5	14.1	167.5	308.7	0	568.3
Per Capita Share of Federal Revenues	43.8	149.1	250.1	43.4	71.6	85.6	2.2	645.8

Source: The Conference Board of Canada.

Chapter 3: Economic Impacts Associated With the Operation of the Trans Mountain Expansion

The nature of the oil pipeline industry dictates that the scale of the effects associated with the operational phase of the Project is very different than the construction phase. The pipeline industry is heavily capital intensive; the amount of capital stock per employee in the industry is 50 times the average for all sectors in Canada.[8] This means that a pipeline project involves large upfront costs during its development stage. Meanwhile, the subsequent operational stage generates much smaller employment effects in any given year. For example, the entire oil pipeline industry in Canada employed only 2,700 people in 2012 according to Statistics Canada's Labour Force Survey.

Although the direct employment effects for the oil pipeline industry are generally very small, it still generates considerable GDP effects. There are several factors that determine an industry's GDP, including the wages and salaries that it pays, the amount of depreciation it records on its assets, and the profits that it earns. In all three respects the oil pipeline industry is above average. As a result, the oil pipeline industry has a very high ratio of GDP per employee; at $783,703 per employee it is nearly nine times the average for all industries.[9]

As well, since pipelines are expected to have extended lives, the cumulative impact over the course of their lives can be significant. This chapter assesses the economic and fiscal impacts of the TMEP's operations over a 20-year time horizon. Although the expected life of the Project is much longer—the existing pipeline has been in operation for nearly 60 years—20 years covers the initial period for which Trans Mountain has firm contracts in place.

3.1 Direct Effects

The assessment of the employment and GDP effects of TMEP operations is based on the incremental revenues that the Project is expected to generate. There are 13 shippers that have entered into binding 15 and 20-year contracts to ship a total of about 708,000 b/d of oil through the pipeline once it is completed. This is equal to about 80 per cent of the pipeline's planned nominal capacity of 890,000 b/d.

Because the terms of these contracts are known, the associated revenues can be reasonably estimated. Annual revenues associated with these contracts were estimated by the Conference Board to be $944 million based on the projected capital costs of the Project and the toll structure that would be applied. This revenue estimate only includes the fixed component of the toll. The variable component is primarily based on the electricity costs associated with shipping through the pipeline and is passed directly through to shippers. As such, the variable component would not have an impact on the labour or material inputs that the pipeline would use, or on the profits that it generates, and is not included when estimating the economic effects.

[8] Based on data from Statistics Canada CANSIM table 031-0002 and the Labour Force Survey.
[9] Based on data from Statistics Canada CANSIM table 379-0031 and the Labour Force Survey.

The 20 per cent of the pipeline's expected capacity that is not committed to firm long-term contracts will be available on a spot or non-firm basis once the Project is operational. We consider the additional economic and fiscal effects of non-firm sales under a different scenario later in this chapter. First, we present an analysis of the effects for the capacity that is committed to long-term contracts. Since the terms of the contracts require shippers to pay for their capacity whether or not they use it, they have a strong incentive to make use of it. As such, the operational economic and fiscal impacts associated with the long-term contracts can be considered the minimum effects associated with operating the pipeline.

For the purposes of this analysis we assume that the full 708,000 b/d of capacity will be covered by long-term contracts over the 20-year period. A portion of the capacity committed to long term contracts has the potential to become available for non-firm sales after 15 years. However, we assume that the relevant contracts will be renewed for an additional five year period; this is an option available in the contracts. Otherwise, we expect that Trans Mountain would attempt to find other firm contract customers for that capacity, which would have the same effect.

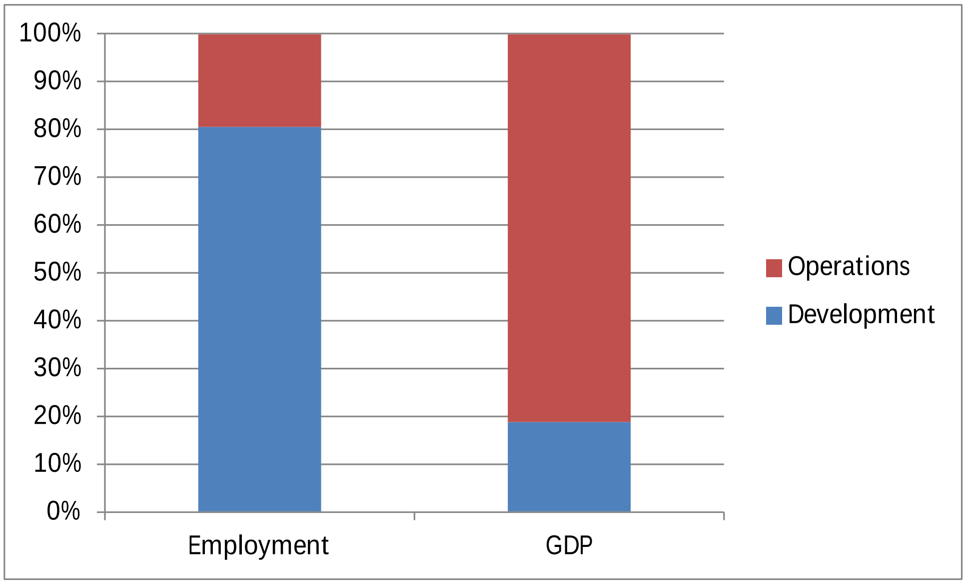
The other consideration when estimating the economic impacts of the pipeline's operations is that 300,000 b/d of capacity is already in place. The TMEP would expand this capacity to 890,000 b/d. However, even if the TMEP were not to proceed, the existing capacity would continue to operate. As such, we only consider the impact associated with the expanded operations rather than the existing pipeline. Information provided by Trans Mountain indicates that the revenues associated with the existing pipeline are approximately $300 million per year. Once this is removed from the revenues associated with the long-term contracts for the TMEP, the Project will generate a $644 million increase in annual revenues.

Based on annual revenue of $644 million, the TMEP will directly support 342 jobs per year, for a total of 6,841 person years of employment over the first 20 years of the pipelines operations. The majority of these positions will be found in British Columbia, which will account for 242 jobs per year or 71 per cent of the total, with the rest being located in Alberta. This reflects the location of pipeline related facilities, such as pumping stations and terminals, which will require employees to operate them.

In terms of GDP, the TMEP is expected to generate $469 million of GDP annually, or $9.4 billion over the first 20 years of its operations. The GDP results standout from the employment results in a couple of ways. First, Alberta's share of the direct GDP effects associated with pipeline operations is larger at 31.4 per cent, versus 29.3 per cent for employment. This reflects the fact that the average wages and salaries per employee in the oil pipeline industry in Alberta are higher than in British Columbia.

Secondly, the comparison of the GDP effects between the development and operational stages of the Project is very different than the employment effects. Operations will account for one-fifth of the employment effects, but 81 per cent of the total GDP effects associated with the development and operation of the project. (See Chart 17.) The reason why the GDP effects are so much larger is because the GDP per employee in the oil pipeline industry is so high. GDP per employee in the industry is very high because of the high levels of capital invested per employee, which results in high labour productivity.

Chart 17. The Direct Effects of Operations on GDP are Much Larger than for Employment
(share of employment and GDP effects by project stage)



Source: The Conference Board of Canada.

3.2 Indirect Effects

As with the development phase, the TMEP will also generate indirect or supply chain effects once it is operational. An estimated 1,492 jobs will be supported by the pipeline in every year of operations. This is equivalent to 29,845 person-years of employment over the first 20 years of the Project's life. Thus, for every job created directly by the TMEP another 4.4 are supported indirectly. This is a high employment multiplier and it is largely a reflection of the small direct employment effects in the oil pipeline industry.

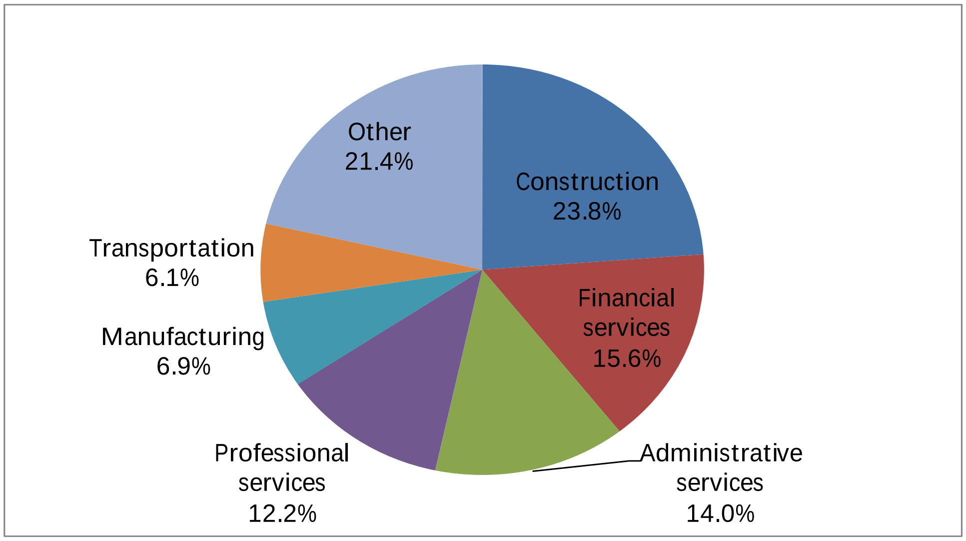
The opposite situation is apparent with the indirect GDP effects. The operation of the TMEP will support $136 million of indirect GDP annually, which is equivalent to only $0.29 for every dollar of direct GDP. This is a very low GDP multiplier and it reflects the high level of direct GDP that the oil pipeline industry generates.

Although the number of indirect jobs supported by the operation of the TMEP is not particularly large in any given year, over the first 20 years of the pipeline's operations they actually exceed those supported by the development of the pipeline—29,845 person-years of employment versus 14,055. What is more, the indirect effects have a somewhat different industrial and regional mix. Regionally, the operational impacts are even more heavily focused in British Columbia., Sectors like construction and administrative services, which include activities like services to buildings and employment services, grow in importance.

3.2.1 Indirect Effects by Sector

The indirect employment effects that arise from pipeline operations are largely confined to six broad sectors. In order of size, they include construction, financial services, administrative services, professional services, manufacturing and transportation. Combined, these six sectors account for 79 per cent of the indirect employment effects. (See Chart 18.) The effects within some of these sectors are similar to what was discussed as part of the development phase in Chapter 2, but in general the impacts on specific industries can be quite different for operations than for the development phase.

Chart 18. Key Sectors that Experience Supply Chain Effects from Operations (share of indirect employment effects from operations)



Source: The Conference Board of Canada.

Also notable is the importance of electricity as an input into the oil pipeline industry. Although it accounts for only 3.2 per cent of the supply chain employment effects, it accounts for 12.4 per cent of the indirect GDP effects. Like the pipeline industry, electricity generation is heavily capital intensive, which leads to it generating very large GDP effects, but limited employment effects. As such, although electricity is a major input into the oil pipeline industry, the employment impacts associated with this spending are small.

3.2.1.1 Construction

The TMEP is expected to support 355 indirect jobs annually in the construction sector once it is operational. The key reason for this will be ongoing maintenance and repairs. All of these jobs will be found in either British Columbia or Alberta, along the route of the proposed pipeline. The jobs will be heavily weighted towards British Columbia, which will account for 94 per cent of the total. The fact that more of the pipeline is located in British Columbia, there are more pump stations located there, and the more difficult terrain that the pipeline traverses in the province all contribute to this difference.

3.2.1.2 Financial Services

Since the financial services sector provides inputs into essentially every industry, it is a key component of the supply chains for many of them. However, with 232 jobs being indirectly supported in the financial services sector annually, it accounts for 15.6 per cent of the total employment effects associated with the operation of the TMEP. These impacts are concentrated among holding companies, investment services, banking, and insurance.

Regionally, the impacts in the financial services sector are more widely dispersed, with 29 per cent of the employment effects occurring outside of British Columbia and Alberta. Most of these effects occur in Ontario, particularly in the investment services and banking industries. These services tend to be more tradable and Ontario's well developed financial services sector means that businesses are more likely to make use of financial institutions that are located in that province.

3.2.1.3 Administrative Services

Administrative services businesses are primarily engaged in activities that support the day-to-day operations of other organizations. A total of 209 indirect jobs in the administrative services sector will be supported by TMEP operations each year. Key administrative industries that provide inputs into the oil pipeline industry include services to buildings (such as janitorial and pest control services), employment services, waste remediation, and security services.

Once again, the employment effects in the administrative services sector are concentrated in British Columbia (54.9 per cent), Alberta (21.8 per cent), and Ontario (17.3 per cent). The limited tradability of some services is a factor that restrains the impacts outside of British Columbia and Alberta. Most of the impacts in Ontario occur in the employment services industry, which has a higher degree of tradability.

3.2.1.4 Professional Services

A total of 182 professional service jobs are supported annually as a result of the supply chain effects associated with the operation of the TMEPs. However, the operating effects on the sector are very different than those associated with the development of the Project. Instead of the main effects occurring in the engineering industry, it is the computer services industry where the largest impacts occur, with 5.8 per cent of the total indirect employment effects occur in the computer services industry. Other industries within professional services that experience notable employment effects include engineering, accounting, and consulting.

Regionally, we see a similar pattern of the largest impacts occurring in British Columbia (41.2 per cent), Alberta (29.6 per cent), and Ontario (20.5 per cent). The impacts in the other provinces are very small, with Quebec accounting for nearly all of the remaining impact. Most of the professional services jobs that are supported outside of British Columbia and Alberta are computer services positions.

3.2.1.5 Manufacturing

The indirect impacts among the particular industries within the manufacturing sector associated with operations are similar to those for the development phase of the Project. Key manufactured inputs include architectural metals, boilers and tanks, and cement products. This reflects the need for ongoing maintenance and repairs on the pipeline's infrastructure over its useful life. However, the scale is smaller. Only 103 manufacturing jobs are expected to be supported annually by TMEP operations, equivalent to 2,020 person-years of employment over the first 20 years of operations. This is only about two-thirds of the manufacturing employment impacts that will occur during the development phase.

The diversity of the regional impacts within the manufacturing sector are also much less during the operating phase of the Project versus the development phase. British Columbia experiences the largest impact (52 per cent), followed by Ontario (18.3 per cent), and then Alberta (14.8 per cent). The key reason for British Columbia accounting for a much higher share of the manufacturing effects during the operational phase is the change in the mix of manufactured inputs. For example, cement products, wood products and printing are all industries that experience a relative increase in their importance. Wood products produced in British Columbia are readily available, while the cement products and printing industries tend to be much more regionally focused than many other segments of the manufacturing sector.

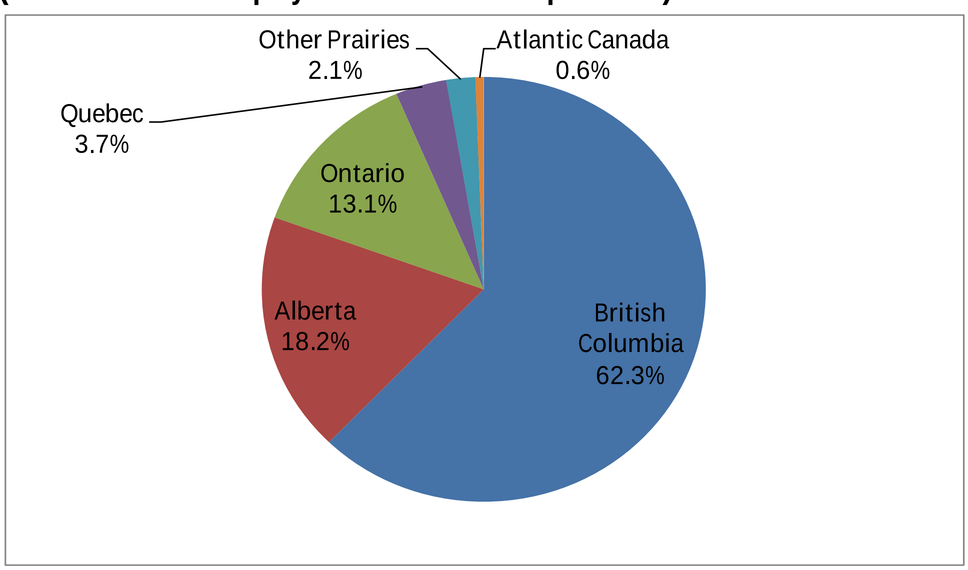
3.2.1.6 Transportation

The last major sector where considerable indirect employment effects occur as a result of TMEP operations is transportation, with 81 jobs being supported annually. Most of these jobs occur in the couriers and messengers, transportation support services, and trucking industries. The impact in the couriers and messengers industry reflects the standard day-to-day need for businesses to interact with other organizations. The impacts in the other transportation industries reflect the need to supply the TMEP with materials and supplies on an ongoing basis. The geographically dispersed nature of the pipeline also contributes to the need for transportation services. As well, the majority of the employment impacts occur in British Columbia, which accounts for 56 per cent of the total. Most of the remaining effects occur in Alberta (18.6 per cent) and Ontario (17.4 per cent).

3.2.2 Indirect Effects by Region

Nearly all of the indirect effects associated with operations of the TMEP occur in British Columbia, Alberta, or Ontario; only 6.5 per cent of the employment effects occur in other provinces. (See Chart 19.) The main reason for this is the importance of construction activity as an input into the oil pipeline industry, which by necessity is almost entirely conducted locally. Many of the other key inputs provided by sectors like administrative services and professional services require a local presence as well.

Chart 19. Supply Chain Employment Effects from Operations by Region (share of indirect employment effects from operations)



Source: The Conference Board of Canada.

3.2.2.1 British Columbia

British Columbia experiences the majority of the supply chain effects associated with the operation of the TMEP. A total of 932 jobs are expected to be supported annually in the province, equivalent to 18,641 person-years or 62 per cent of employment over the first 20 years of operations. This is more than double the supply chain impacts in British Columbia associated with developing the Project. Industries that experience notable supply chain effects in British Columbia include repair construction, services to buildings, holding companies, and electric power generation.

3.2.2.2 Alberta

Nearly 20 per cent of the employment supported by the supply chain effects associated with the operation of the TMEP occurs in Alberta. In total, 273 jobs will be supported in Alberta annually, equivalent to 5,460 person-years of employment over the first 20 years of operations. In comparison, the development of the TMEP will support 3,660 person-years of employment in Alberta. Industries that experience significant indirect effect in Alberta include computer services, holding companies, electric power generation, construction, and employment services.

3.2.2.3 Ontario

Ontario is the only other province to experience substantial supply chain effects as a result of TMEP operations, with 195 jobs being supported annually, or 3,895 person-years of employment over the first 20 years of operations. Again the indirect operational impacts in Ontario are actually larger than the development impacts. The largest impacts in Ontario include the computer and employment services industries. As well, several different types of financial services industries benefit including banking, investment services, and holding companies.

3.2.2.4 Other Regions

The indirect employment impacts associated with the operation of the TMEP are much more modest in the rest of the country. Across all of the other provinces the employment impacts total only 99 jobs annually, or 1,970 person-years of employment over 20 years. In some cases, such as Saskatchewan, the impacts of operations are actually less than those from the Project's development. This reflects the fact that a good portion of the pipe used to initially build the pipeline would be sourced in Saskatchewan according to the modelling results. The impacts are generally spread across a variety of industries, but the largest impacts in other regions occur in industries like computer services, investment services, and holding companies.

3.3 Induced Effects

As with the development phase of the Project, the wages earned in the direct and indirect jobs supported by TMEP operations will generate additional economic effects when they are spent. These induced effects add considerably to the total economic effects associated with TMEP operations. However, in the case of operations, the induced effects are smaller than the indirect effects. The opposite was true for the induced effects from the development phase.

The key reason for the difference is that the direct employment effects of operations are much smaller than for development. Even though the direct jobs in the oil pipeline industry are very high paying, there are fewer of them. The end result is the labour income that results from direct and indirect employment during the operational phase is only $2.45 billion over 20 years of operations, versus $2.62 billion for the Project's development. Less labour income to spend results in smaller induced effects.

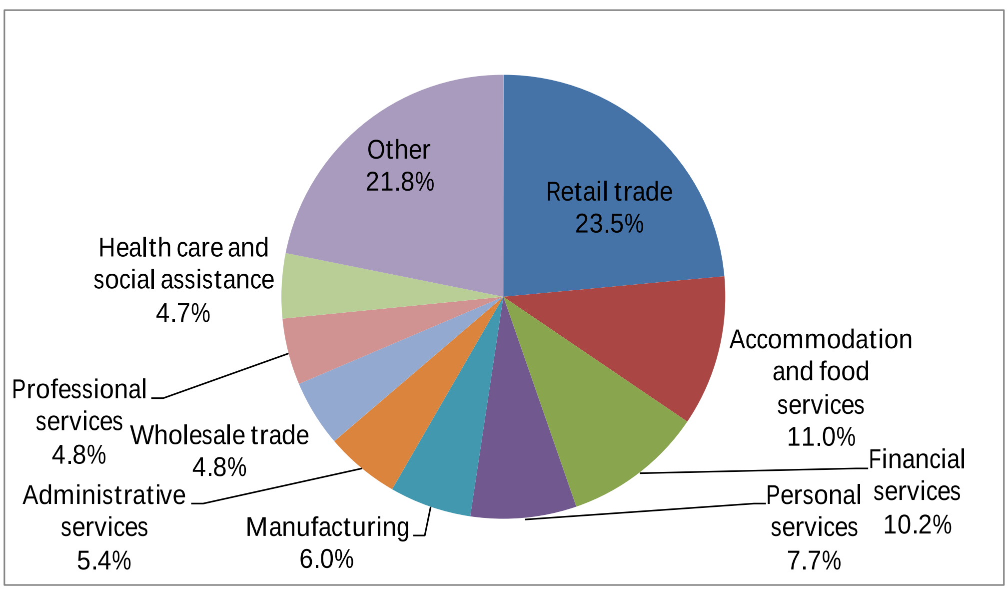
In total, 13,588 person-years of induced employment would be supported by pipeline operations over the first 20 years of operations, equivalent to 679 jobs per year. Thus, the combined direct, indirect, and induced employment impacts associated with pipeline operations will be 50,274 person-years over 20 years, or 2,514 jobs per year.

The induced GDP effects are also considerable. For every $1 in GDP directly created as a result of the pipeline's operations, another $0.13 is supported by the induced effects, compared to $0.29 in supply-chain benefits. This represents a total GDP effect of $13.3 billion over the first 20 years of operations. Thus the combined development and operational GDP effects associated with the TMEP are $18.2 billion.

3.3.1 Induced Effects by Sector

In terms of the industries where the induced impacts occur, the mix is very similar to those discussed in Chapter 2. The same group of consumer oriented sectors, including retail trade, accommodation and food services, financial services, and personal services account for most of the effects. (See Chart 20.) The pattern of induced effects reflects how people spend their money, and that generally is not dependent on how they earn that money. The modest differences in the sectoral induced effects between the operational and development phases of the Project are caused by the different regional mix for the direct and indirect effects. Essentially, people's consumption patterns vary only modestly across regions.

Chart 20. Induced Employment Effects from Operations by Sector
(share of induced employment effects from operations)

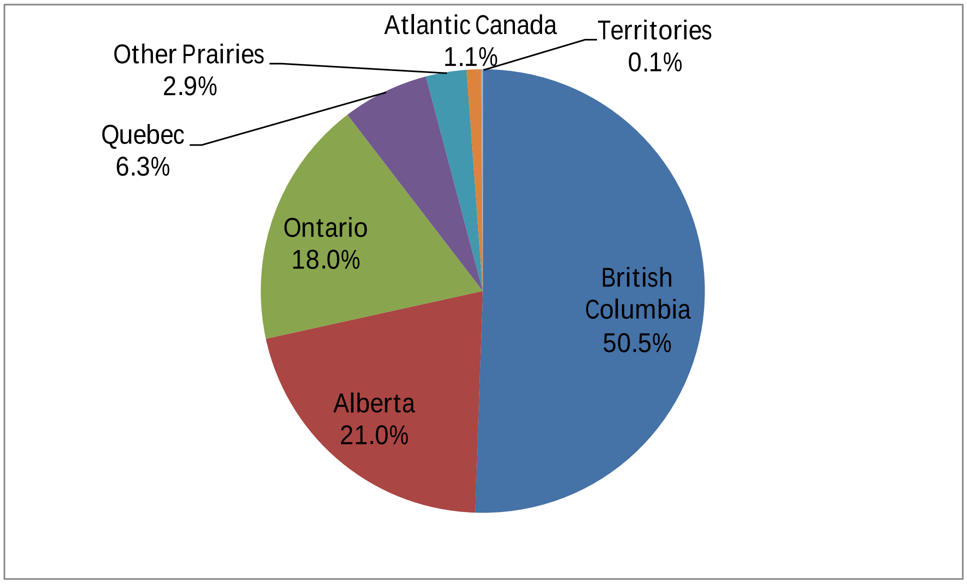


Source: The Conference Board of Canada.

3.3.2 Induced Effects by Region

The regional distribution of the induced effects is again similar to what occurs during the development phase of the Project. British Columbia (6,868 person-years) and Alberta (2,853 person-years) account for 72 per cent of the total effects. (See Chart 21.) However, since 87 per cent of the labour income generated by the direct and indirect effects is in those two provinces, this result is not surprising. The reason why the induced effects are more spread out geographically is because some of the things people buy in British Columbia and Alberta are sourced from other parts of the country.

Chart 21. Induced Employment Effects from Operations by Region
(share of induced employment effects from operations)



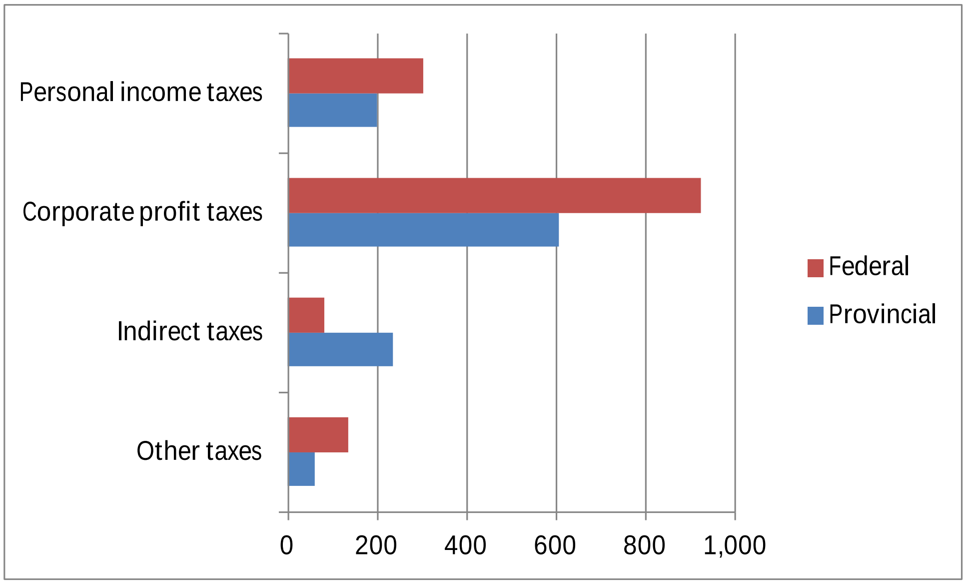
Source: The Conference Board of Canada.

3.4 Fiscal Effects

The direct, supply chain, and induced effects associated with the operation of the TMEP also have fiscal implications at both the provincial and federal level. Over the first 20 years of its life, the TMEP is expected to generate $2.5 billion in federal and provincial government revenues. This is more than double the $1.2 billion in fiscal impacts associated with the development phase of the Project. The operational fiscal impacts are heavily weighted towards corporate income taxes, which account for 60 per cent of the combined provincial and federal fiscal impacts. (See Chart 22.) Personal income taxes and indirect taxes, such as sales taxes account for most of the remaining fiscal impacts.

The key reason for the large role of corporate taxes in the fiscal effects is the breakdown of the GDP effects for TMEP operations. As indicated previously, the oil pipeline industry generates a high level of GDP. Because of this, the direct GDP effects account for 70 per cent of the total operational GDP effects. At the same time, the oil pipeline industry is highly capital intensive, so most of the GDP generated by the industry comes in the form of depreciation of its assets and corporate profits. Since it is the income components of GDP, including corporate profits and labour income, that determine most of the fiscal effects, the end result is that corporate profits in the oil pipeline industry are the key factor driving the results.

Chart 22. Corporate Income Taxes Account for Most of the Operations Related Fiscal Effects (tax revenues over 20 years of operations, millions of 2012$)



Source: The Conference Board of Canada.

3.4.1 Federal Impacts

The federal government will be the major beneficiary of the fiscal impact from TMEP operations, at $1.4 billion. This is equivalent to 0.6 per cent of federal government revenues in 2012. Corporate income taxes are the largest portion of this, at $925 million. This is followed by personal income taxes ($303 million) and indirect taxes ($83 million). Increased contributions to social security programs, such as employment insurance, are also significant, at $66 million.

Federal government revenues are equivalent to $11 for every $100 of GDP generated by the Project's operations. This is somewhat lower than the $13 of federal tax revenues for every $100 of GDP generated by the development phase of the Project. The key reason for this is the shift towards corporate profits as the main source of government revenue. The marginal tax rate on corporate profits is generally lower than the rate for personal income. As well, consumers pay sales taxes on the goods and services they buy, while businesses often get the sales taxes they pay refunded through input tax credits.

3.4.2 Provincial Impacts

In aggregate, the TMEP is expected to support $1.1 billion in provincial government revenues over the first 20 years of its life. This is equivalent to 0.3 per cent of total provincial revenues in 2012. At $607 million, corporate income taxes will account for the majority of the provincial fiscal effects. Indirect taxes (which include sales taxes) and personal income taxes account for most of the rest of the effects, at $237 million and $200 million, respectively.

In terms of the breakdown by province the largest benefits would accrue to British Columbia, which would receive 66 per cent of the total, or $727 million, which is equivalent to 1.7 per cent of British Columbia's 2012-13 revenues.[10] Alberta would receive most of the rest of the provincial fiscal effects, at $278 million, equivalent to 0.7 per cent of the province's 2012-13 revenues. Ontario ($60 million), Quebec ($18 million), Saskatchewan ($8 million), and Manitoba ($5 million) will experience much more modest fiscal effects. For the Atlantic provinces, the fiscal effects are very small. However, if we redistribute the federal fiscal effects across the provinces on a per capita basis, then all of the provinces will experience a larger effect. (See Table 4.)

Table 4. Summary of Fiscal Effects from TMEP Operations
(tax revenues over 20 years of operations, millions of 2012$)

	Direct Provincial Revenues	Per Capita Share of Federal Revenues	Total
British Columbia	277.5	160.3	437.8
Alberta	727.0	191.8	918.8
Ontario	59.9	560.2	620.1
Quebec	18.1	334.0	352.1
Other Prairies	13.8	97.3	111.0
Atlantic Canada	5.9	98.1	104.0
Territories	0.0	4.7	4.7
Total	**1,102.1**	**1,446.4**	**2,548.6**

Source: The Conference Board of Canada.

3.5 The Economic Effects of Non-Firm Transactions

All of the impacts discussed thus far in this chapter are based only on the transportation of volumes that are linked to long-term contracts. These can be considered the minimum economic and fiscal effects associated with the TMEP. There will be about 180,000 b/d of nominal capacity available for non-firm or spot transactions, and the degree to which this capacity is used will determine the amount of additional economic impacts. There are two key considerations concerning the effects of the non-firm capacity. The first is the toll that will be applied to any non-firm transactions. The second is the volumes that will be transported.

The tolls for non-firm capacity will be higher than for product shipped under the terms of long-term contracts. The non-firm toll will be based on a 10 per cent premium to the 15-year firm toll. However, those shippers who signed 20-year contracts receive a 10 per cent discount from the 15-year rate, and large volume shippers (those who contracted for 75,000 b/d or more) receive an additional 7.5 per cent discount.[11]

[10] Government of British Columbia. *June Update: Budget and Fiscal Plan 2013/14-2015/16.*
[11] Transmountain Pipeline. *TMEP Toll Application.*

Based on information provided by Trans Mountain,[12] the average fixed toll that will be applied under long-term contracts was estimated by the Conference Board of Canada to be $3.66, assuming no change in the capital costs associated with the Project. For non-firm shippers, the estimated toll is $4.59. The higher toll on non-firm capacity results in higher revenues on a per barrel basis up to 85 per cent capacity utilization of the TMEP. However, once capacity utilization exceeds 85 per cent, under the revenue sharing provisions of the contracts any additional revenues will be split on a 50/50 basis between shippers and Trans Mountain through reductions in the variable toll.[13] As such, the additional revenues to Trans Mountain from non-firm shipments depend on capacity utilization rates.

If we assume that the available non-firm capacity on the TMEP system is fully utilized over its first 20 years of operations, the calculated economic and fiscal effects based on that assumption represent the maximum potential impact associated with the Project. The reality is likely to fall somewhere in between the minimum and the maximum.

We can use the previously discussed modelling results for TMEP operations to determine the expected economic and fiscal impacts associated with the non-firm transactions. One of the benefits of using an I/O model is that its results are scalable. Since the model is based on a snapshot in time, the relative effects are fixed. Thus, higher revenues from non-firm volumes will result in a proportionate increase in the supply chain and induced effects, while the mix of regions and industries will be unaffected.

Based on an average toll rate of $4.59 per barrel, a non-firm capacity of approximately 180,000 b/d, and revenue sharing on capacity used above 85 per cent, we estimate the maximum annual revenues associated with non-firm capacity to be $191 million. This increases the total annual incremental revenues associated with TMEP operations to $835 million, a 30 per cent increase over the revenue estimated for the fixed contracts alone. Thus, the economic and fiscal impacts in the “maximum” scenario can be expected to be 30 per cent higher than in the “minimum” scenario.

Table 5 provides a summary of the minimum and maximum effects of TMEP pipeline operations over its first 20 years. In the maximum scenario, the combined direct, indirect, and induced employment effects increase from 50,723 to 65,184 person-years. As well, the GDP impacts rise from a cumulative total of $13.3 billion to $17.3 billion. Finally, the combined federal and provincial fiscal impact rises from $2.5 billion to $3.3 billion.

[12] The weighted average 2018 contract toll was determined by dividing initial year contract revenue by total contract volume.
[13] Transmountain Pipeline. *TMEP Toll Application.*

Table 5. Summary of the Regional Impacts of TMEP Operations (cumulative effects, 2018-2037)

	Atlantic Canada	Quebec	Ontario	Other Prairies	Alberta	British Columbia	Territories	Canada
	MINIMUM EFFECTS (LONG-TERM CONTRACTS)							
Employment effects (person-years)	**327**	**1,970**	**6,345**	**1,025**	**10,293**	**30,269**	**43**	**50,273**
Direct	0	0	0	0	2,005	4,836	0	6,841
Indirect	184	1,113	3,895	625	5,435	18,565	28	29,845
Induced	143	857	2,450	400	2,853	6,868	15	13,588
GDP effects (millions of 2012$)	**24.3**	**165.6**	**542.9**	**87.0**	**3,958.1**	**8,540.2**	**4.5**	**13,322.5**
Direct	0.0	0.0	0.0	0.0	2,947.9	6,427.8	0.0	9,375.7
Indirect	13.7	94.8	330.4	54.3	711.7	1,505.6	3.0	2,713.4
Induced	10.6	70.9	212.5	32.7	298.5	606.8	1.5	1,233.4
Fiscal Impact (millions of 2012$)	**104**	**352.1**	**620.1**	**111.1**	**469.3**	**887.3**	**4.7**	**2,548.6**
Direct Provincial Revenues	5.9	18.1	59.9	13.8	277.5	727.0	0	1,102.2
Per Capita Share of Federal Revenues	98.1	334.0	560.2	97.3	191.8	160.3	4.7	1,446.4
	MAXIMUM EFFECTS (INCLUDING SPOT VOLUMES)							
Employment effects (person-years)	**425**	**2,555**	**8,226**	**1,330**	**13,346**	**39,246**	**56**	**65,184**
Direct	0	0	0	0	2,600	6,270	0	8,870
Indirect	239	1,443	5,050	810	7,047	24,071	36	38,696
Induced	186	1,112	3,177	519	3,699	8,905	20	17,618
GDP effects (millions of 2012$)	**31.5**	**214.8**	**703.9**	**112.8**	**5,131.9**	**11,073.0**	**6.4**	**17,274.3**
Direct	0.0	0.0	0.0	0.0	3,822.2	8,334.2	0.0	12,156.4
Indirect	17.8	122.9	428.4	70.4	922.7	1,952.1	4.3	3,518.5
Induced	13.7	91.9	275.5	42.4	387.0	786.8	2.1	1,599.4
Fiscal Impact (millions of 2012$)	**134.8**	**456.5**	**804.0**	**144.1**	**608.5**	**1150.5**	**6.7**	**3,305.1**
Direct Provincial Revenues	7.6	23.5	77.7	17.9	359.8	942.6	0.0	1,429.1
Per Capita Share of Federal Revenues	127.2	433.1	726.3	126.2	248.7	207.8	6.7	1,876.0

Source: The Conference Board of Canada.

3.6 Summary

Both the development and operational phases of the TMEP will generate economic and fiscal benefits. In general, the economic and fiscal effects associated with operating the pipeline will exceed those experienced during the construction phase of the Project, although the operational effects will be spread over a longer period of time. At a minimum, both phases of the Project are expected to support 108,310 person-years of employment and $3.8 billion in fiscal effects between 2012 and 2037. (See Table 6.) If the available non-firm capacity on the TMEP is fully utilized these effects increase to 123,221 person-years of employment and fiscal effects of $4.5 billion.

This chapter and the previous one discussed the economic and fiscal impacts associated with building and operating the TMEP. However, the pipeline is also expected to reduce the discounts on Canadian heavy oil that have been experienced in recent years. The higher received prices for producers, or “netbacks,” will have additional fiscal implications for Canada. The next chapter discusses those impacts.

Table 6. Summary of the Regional Impacts of TMEP Development and Operations (cumulative effects, 2012-2037)

	Atlantic Canada	Quebec	Ontario	Other Prairies	Alberta	British Columbia	Territories	Canada
	MINIMUM EFFECTS (LONG-TERM CONTRACTS)							
Employment effects (person-years)	**617**	**3,372**	**11,004**	**2,124**	**24,926**	**66,132**	**135**	**108,310**
Direct	0	0	0	0	9,532	25,511	0	35,043
Indirect	326	1,714	6,235	1,270	9,095	25,164	97	43,900
Induced	291	1,659	4,769	855	6,298	15,458	38	29,368
GDP effects (millions of 2012$)	**46.0**	**285.8**	**951.5**	**185.5**	**5,360.5**	**11,329.2**	**15.7**	**18,174.2**
Direct	0.0	0.0	0.0	0.0	3,598.0	7,945.8	0.0	11,543.8
Indirect	24.5	147.5	538.1	115.7	1,105.7	2,020.3	12.0	3,963.9
Induced	21.5	138.2	413.4	69.8	656.8	1,363.1	3.7	2,666.4
Fiscal Impact (millions of 2012$)	**152.2**	**518.3**	**926.7**	**168.6**	**708.4**	**1281.6**	**6.9**	**3,762.7**
Direct Provincial Revenues	10.3	35.2	116.4	27.9	445	1035.7	0	1,670.5
Per Capita Share of Federal Revenues	141.9	483.1	810.3	140.7	263.4	245.9	6.9	2,092.2
	MAXIMUM EFFECTS (INCLUDING SPOT VOLUMES)							
Employment effects (person-years)	**714**	**3,957**	**12,886**	**2,429**	**27,978**	**75,110**	**148**	**123,221**
Direct	0	0	0	0	10,127	26,945	0	37,072
Indirect	381	2,044	7,390	1,455	10,707	30,670	105	52,751
Induced	333	1,913	5,496	973	7,144	17,495	43	33,398
GDP effects (millions of 2012$)	**53.2**	**334.9**	**1,112.5**	**211.3**	**6,534.4**	**13,862.1**	**17.6**	**22,126.0**
Direct	0.0	0.0	0.0	0.0	4,472.3	9,852.2	0.0	14,324.5
Indirect	28.6	175.6	636.1	131.8	1,316.7	2,466.8	13.3	4,769.1
Induced	24.6	159.3	476.4	79.5	745.3	1,543.1	4.3	3,032.4
Fiscal Impact (millions of 2012$)	**183.0**	**622.7**	**1110.6**	**201.6**	**847.6**	**1544.8**	**8.9**	**4,519.2**
Direct Provincial Revenues	12.0	40.6	134.2	32.0	527.3	1,251.3	0.0	1,997.4
Per Capita Share of Federal Revenues	171.0	582.2	976.4	169.6	320.3	293.4	8.9	2,521.8

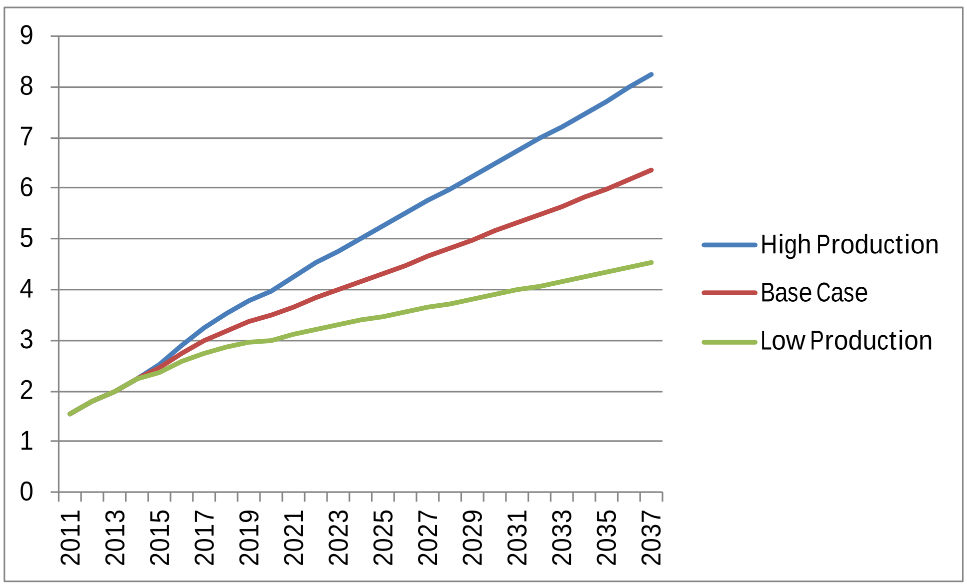
Source: The Conference Board of Canada.

Chapter 4: The Fiscal Impacts of Higher Netbacks for Canadian Oil Producers

In addition to the economic and fiscal impacts outlined in the previous two chapters, there are other implications associated with the development of the TMEP. One of these is the potential for Canadian oil producers to obtain a higher price for their product. The IHS Global Canada Ltd. (IHS) study concludes that the TMEP will help to alleviate the discounting of Canadian crude experienced in recent years and will contribute to higher prices received or "netbacks" for Canadian producers.[14]

IHS developed three different production cases for Western Canadian oil production.[15] (See Chart 23.) In all three cases, it is assumed that the Keystone XL pipeline will be built in 2015. In addition, IHS models the price impact of TMEP, Energy East, and Northern Gateway all being completed in 2017/2018 versus a world where they are not built. In every case, the construction of these pipelines results in higher netbacks for all producers of heavy oil (both conventional and diluted bitumen) in Western Canada.

Chart 23. Western Canadian Oil Production Could Take Different Paths
(Western Canadian heavy oil supply, millions of barrels per day)



Source: IHS.

These higher netbacks would lead to higher revenues, and in turn higher profits, which would have real economic consequences, such as increased dividend payments or business investment. As well, there will be fiscal implications in terms of higher royalties and corporate income taxes paid to federal and provincial governments. It is important to note that these benefits will arise regardless of whether or not oil production or investment increases beyond what is currently expected – higher prices alone are

[14] Kelly, Steve. *Trans Mountain Expansion Direct Evidence.*
[15] Kelly, Steve. *Trans Mountain Expansion Direct Evidence.*

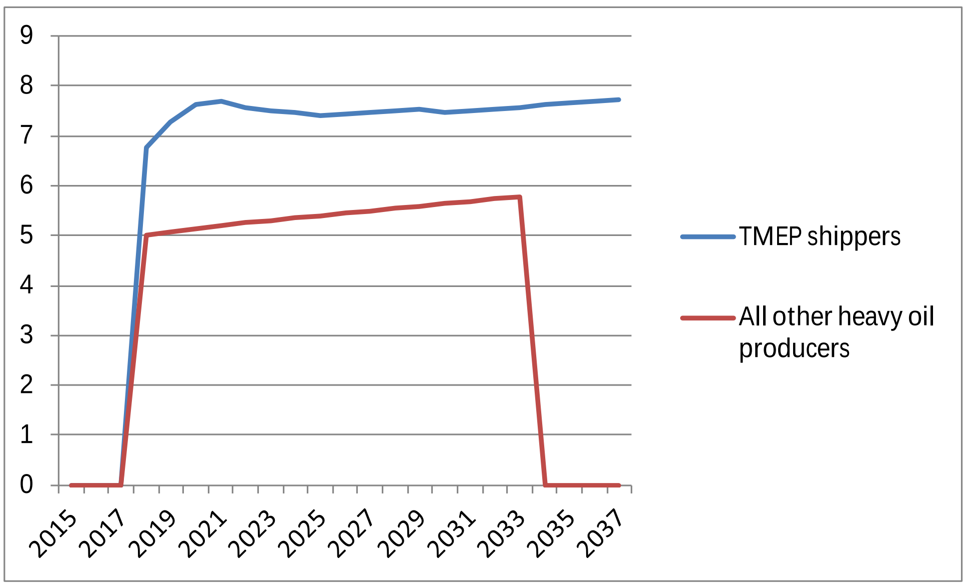
enough to drive positive economic impacts for the Canadian economy. In this study we do not consider the economic effects associated with how producers may make use of higher netbacks. Instead, the rest of this chapter discusses the industry revenue and fiscal implications of higher netbacks associated with pipeline capacity additions in each of the cases.

4.1 The Base Case

In the IHS base case, significant volumes of heavy oil are projected to begin flowing through the TMEP, Energy East, and Northern Gateway pipelines in late 2017. The resulting alleviation of the oversupply situation at Cushing leads to an increase in netbacks for all conventional heavy oil and oil sands producers operating in Western Canada, not just those producers that ship via the TMEP. This situation will persist until 2034, when IHS expects an oversupply situation at Cushing to resume.[16]

According to IHS, shippers of heavy oil on the TMEP will receive additional netback benefits from the market access provided by the TMEP, beyond the general industry benefits expected for all heavy oil producers. Heavy oil shippers on the TMEP that sell into California Asian markets are expected to garner higher prices for their products. This will mean a higher netback of about $7-8 per barrel versus the $5-6 per barrel that other heavy oil producers will experience.[17] (See Chart 24.) As well, this benefit will persist beyond 2033.

Chart 24. Estimated Higher Netbacks for Oil Producers as a Result of Increased Pipeline Capacity (price premium attributable to pipeline additions, US$ per barrel, 2012$)



Source: IHS.

[16] Kelly, Steve. *Trans Mountain Expansion Direct Evidence.*

[17] In the IHS study, these benefits would be realized on volumes shipped to Asia and priced against Middle East crude imported into the region. The benefits for TMEP shippers are based on half of the TMEP firm commitments (equal to 707,500 B/D ÷ 2 = 353,750 B/D) being priced in China rather than in the U.S. Gulf Coast for the period 2018 to 2037.

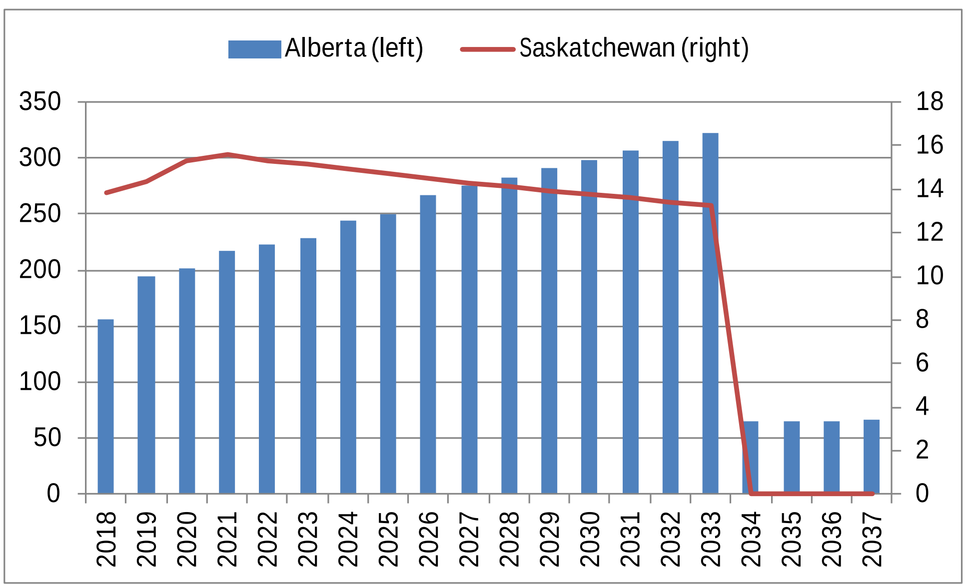
However, not all of the benefits experienced by heavy oil and bitumen producers are attributable to the market access provided by the TMEP. The results are dependent on all three planned pipelines being completed in the 2017/2018 timeframe. As such, IHS attributes 26.6 per cent (equivalent to TMEP's share of the combined assumed capacity additions) of the general industry benefits to TMEP. Thus, TMEP is expected to increase producer revenues by $45.4 billion over the first 20 years of its operations, with $37 billion being attributable to general industry benefits and an additional $8 billion being attributable to TMEP enabling heavy oil shipments to Asia.

4.1.1 Fiscal Impacts: Royalties

Because the TMEP would increase the netbacks for producers without any attendant increase in producers' operating costs, both revenues and profits would be expected to rise by $45.4 billion. This will have implications for the royalties and corporate income taxes that oil producers pay. In the case of royalties, we estimate that Alberta and Saskatchewan will experience a combined increase in royalties of $4.6 billion over the first 20 years of pipeline operations.

At $4.3 billion, Alberta will garner most of these royalty benefits, reflecting the fact that the province accounts for most of the heavy oil production in Western Canada. This corresponds to an annual average of $217 million, which for comparison purposes, is equivalent to about 4 per cent of all oil royalty payments in Alberta in fiscal year 2012-13.[18] However, the benefits will be highest during the 2018-2033 period, when every barrel of diluted bitumen and conventional heavy oil receives a higher price. (See Chart 25.)

Chart 25. Higher Netbacks Will Increase Royalty Collections
(provincial royalty collections due to higher netbacks, millions of 2012$)



Source: The Conference Board of Canada.

[18] Government of Alberta. *Budget 2013: Fiscal Plan Tables.*

Saskatchewan will also see higher royalty payments, although the gains will be commensurately lower in line with the province's lower production levels. Over the period 2018 through 2033, we estimate that the province would collect an additional $230 million in royalty payments as a result of higher netbacks from the TMEP. However, since we do not expect any Saskatchewan oil to actually move through the TMEP, Saskatchewan producers will not experience any benefits after 2033.

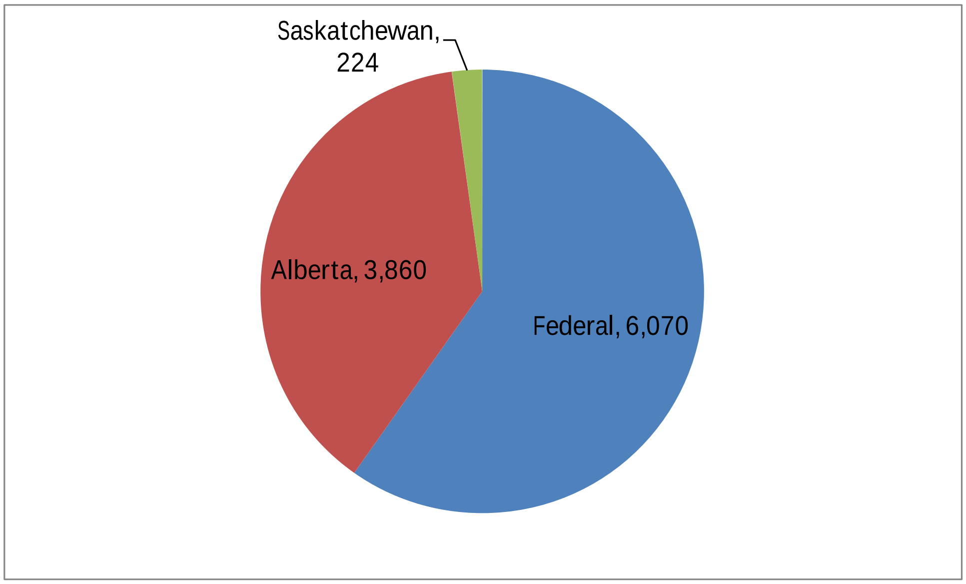
4.1.2 Fiscal Impacts: Income Taxes

Higher profits for oil producers as a result of higher netbacks will also generate significant corporate income tax effects at both the federal and provincial level. Income taxes are applied after royalties are deducted, but the direct link between higher prices and higher profits means that the provincial and federal tax rates are being applied to a sizeable increase in profits. We expect the corporate tax effects to be even larger than the royalty impacts, at $10.2 billion between 2018 and 2037.

Again, as the largest producer, Alberta will garner a sizeable share of this total figure, at $3.9 billion over the same period. Saskatchewan will also benefit, but the fiscal impact will be much smaller at $224 million over the same period. The fact that Saskatchewan heavy oil production is only about one-tenth that of Alberta's and that the ratio is shrinking is one factor. As well, Saskatchewan only garners benefits between 2018 and 2033, when all Canadian heavy oil producers are expected to benefit from higher prices as a result of the TMEP.

As the sole producers of heavy oil and diluted bitumen in Canada, Alberta and Saskatchewan derive all of the benefit from higher provincial tax revenues. But the entire country will also benefit from higher federal corporate income tax collections, which are projected to be larger than those that accrue to Alberta and Saskatchewan combined. (See Chart 26.) Between 2018 and 2037 federal corporate income tax collections are expected to be $6.1 billion higher as a result of the higher netbacks that result from the TMEP. Since federal revenues tend to be distributed back to the provinces on a per capita basis, this will generate significant benefits for all of Canada's regions.

Chart 26. Higher Netbacks Will Result in Sizeable Corporate Income Tax Benefits
(corporate income tax effects due to higher netbacks, millions of 2012$, 2018-2037)



Source: The Conference Board of Canada.

Thus, in the base case, the cumulative fiscal benefits of the TMEP are considerable. Canada as a whole derives an additional $14.7 billion in fiscal revenues between 2018 and 2037. Alberta captures the largest share of this benefit. The combined royalty and provincial corporate income tax effects in the province total $8.2 billion over a 20-year period, or $410 million per year, which is equivalent to 1.1 per cent of provincial revenues in fiscal year 2012-13.[19] But the benefits are not confined to Alberta. Saskatchewan directly garners $454 million of the total fiscal effects between 2018 and 2037, while the rest will be spread across the provinces as part of federal disbursements.

4.2 The Low Production Case

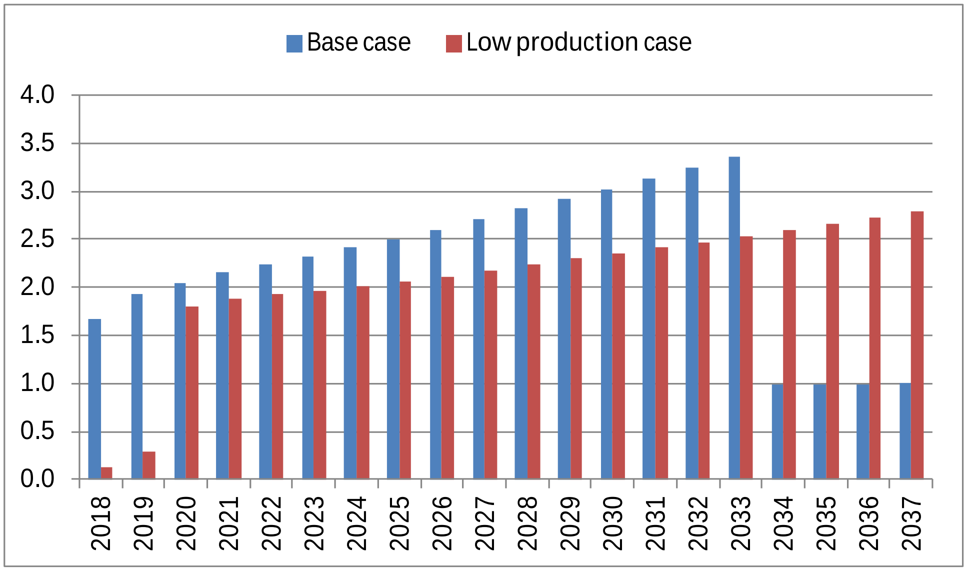
The IHS low production scenario assumes bitumen production is lower than in the base case, but conventional heavy production remains unchanged. In terms of higher netbacks, the key difference between the base case and the low production case is how long it takes for the available supply of oil to again exceed the existing pipeline capacity. In the base case this occurred in 2034, but this is not expected to happen before the end of the forecast period in the low production case. Also of note in the low production case is that the benefit of higher netbacks for non-TMEP shippers does not start until 2020.

In any given year before 2034, the total royalties and corporate income tax collections associated with heavy oil production will be lower in the low production case. Less production leads to lower revenues and profits, and thus lower royalties and corporate income tax collections. However, since the higher netback effects of the TMEP persist for a longer period of time in the low production scenario, IHS estimates oil industry revenues attributable to TMEP to be $41.9 billion. (See Chart 27.) This is only modestly lower than in the base case.

Chart 27. Higher Netbacks Due to TMEP Will Contribute to Higher Oil Producer Revenues

[19] Government of Alberta. *Budget 2013: Fiscal Plan Tables.*

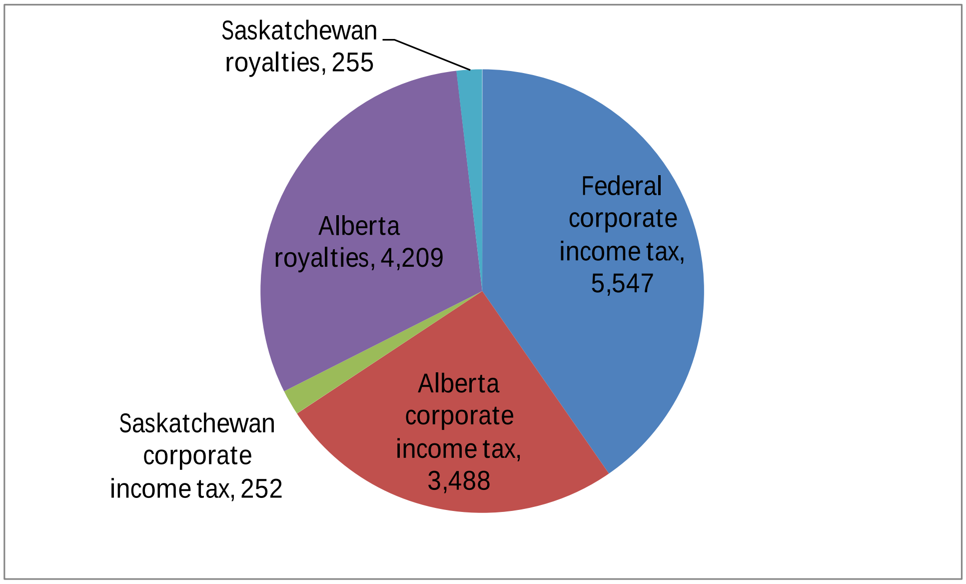
(increase in oil producer revenues attributable to TMEP, billions of 2012$)



Source: IHS.

In total, government revenues are expected to be $13.8 billion higher between 2018 and 2037 as a consequence of the higher netbacks that result from TMEP. Corporate income taxes will again account for the largest share of this total at $9.3 billion. (See Chart 28.) The federal government will experience the largest share of corporate income tax collections (59.7 per cent), followed by Alberta (37.6 per cent), and Saskatchewan (2.7 per cent).

Chart 28. Federal Corporate Income Taxes Experience the Highest Fiscal Impact
(fiscal impacts due to higher netbacks, millions of 2012$, 2018-2037)



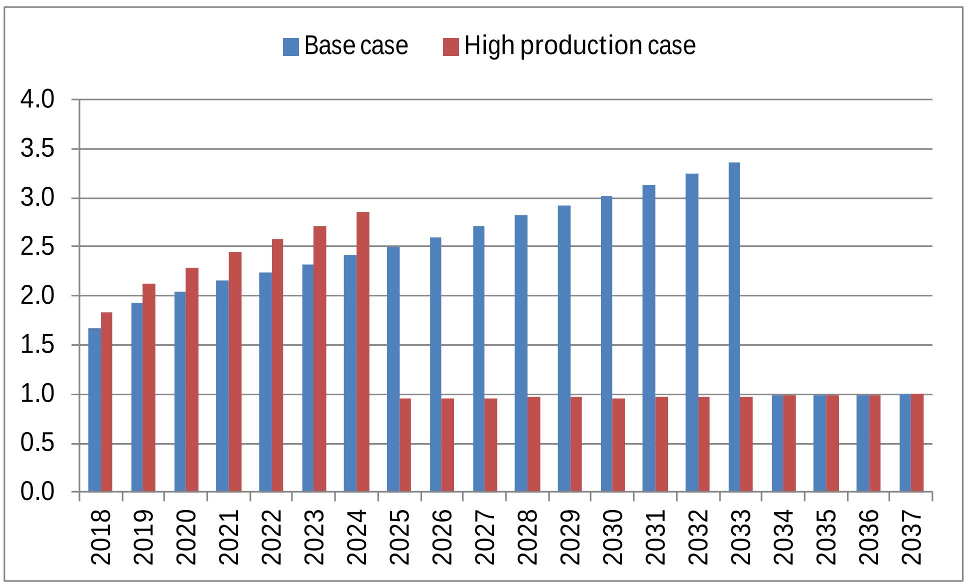
Source: The Conference Board of Canada.

Alberta's royalty collections will be $4.2 billion higher as a result of the higher netbacks over the TMEP's first 20 years of operations. Saskatchewan also benefits from the higher netbacks on conventional heavy oil. Over the same period, its royalty collections are expected to be $255 million higher. Unlike the base case, because the benefits for non-TMEP shippers will persist through the end of the forecast period, Saskatchewan will experience benefits through to 2037.

4.3 The High Production Case

In the IHS high production scenario bitumen production is expected to expand more quickly than in the base case, but conventional heavy production remains unchanged. In terms of higher netbacks, again the key difference in IHS's analysis is how long it takes before the available supply of oil exceeds the existing pipeline capacity. In the base case this occurred in 2034, but in the high production case this occurs much sooner, in 2025. As a result, IHS estimates that total oil producer revenues from higher netbacks attributable to TMEP between 2018 and 2037 as a result higher netbacks to be only $29.7 billion. Thus, the fiscal benefits associated with higher netbacks are the lowest in this scenario. (See Chart 29.)

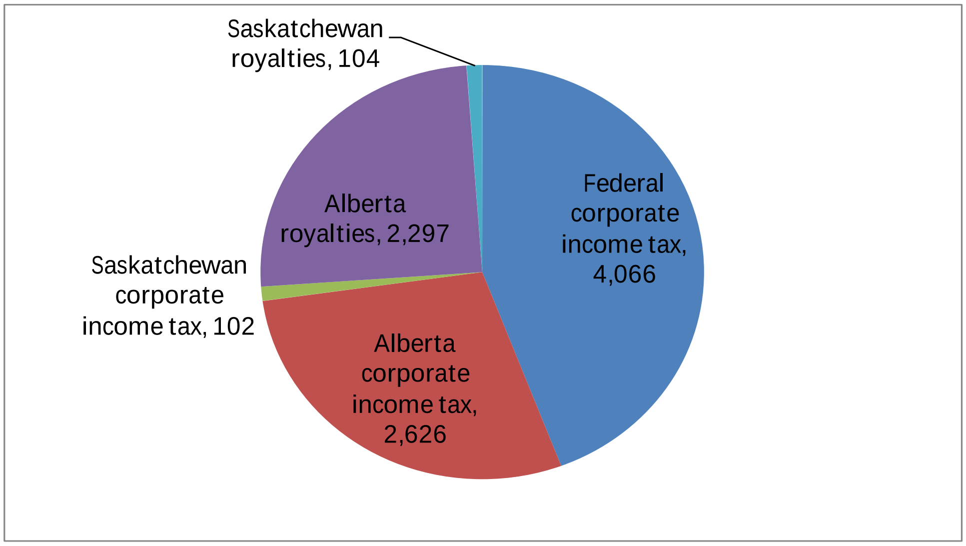
Chart 29. Higher Netbacks Due to TMEP Will Contribute to Higher Oil Producer Revenues (increase in oil producer revenues attributable to TMEP, billions of 2012$)



Source: IHS.

Nevertheless, the fiscal benefits are still significant in this case. In total, government revenues are expected to be $9.2 billion higher between 2018 and 2037 as a result of the higher netbacks that the market access provided by the TMEP will generate. Corporate income tax collections will account for $6.8 billion of this figure, with the federal government garnering the largest share at $4.1 billion, followed by Alberta ($2.6 billion) and Saskatchewan ($102 million). (See Chart 30.) Royalty payments account for the rest of the fiscal effects from higher netbacks, with Alberta's royalties being $2.3 billion higher and Saskatchewan's being $104 million higher.

Chart 30. Summary of the Fiscal Impact in the High Production Case (fiscal impacts due to higher netbacks, millions of 2012$, 2018-2037)



Source: The Conference Board of Canada.

4.4 Summary

The construction and operation of the TMEP and other pipelines is expected to result in higher netbacks to Canadian oil producers. One result of these higher netbacks is higher royalty and corporate income tax payments in the provinces of Saskatchewan and Alberta, as well as at the federal level. In the base case we expect these fiscal benefits to total $14.7 billion over the first 20 years of the pipeline's operations. (See Table 7.) This figure ranges between $9.2 billion in the high production case and $13.8 billion in the low production case.

Table 7. Summary of the Fiscal Impacts of Higher Netbacks (cumulative effects, 2018-2037)

	Atlantic Canada	Quebec	Ontario	Other Prairies	Alberta	British Columbia	Territories	Canada
				Base Case				
Total Impact (millions of 2012$)	**411.8**	**1,401.8**	**2,351.0**	**861.9**	**8,868.9**	**804.9**	**19.7**	**14,720.0**
Provincial Corporate Income Tax	0.0	0.0	0.0	223.8	3,860.2	0.0	0.0	4,084.0
Per Capita Share of Federal Corporate Income Tax	411.8	1,401.8	2,351.0	408.2	672.7	804.9	19.7	6,070.0
Royalties	0.0	0.0	0.0	230.0	4,336.0	0.0	0.0	4,566.0
				Low Production Case				
Total Impact (millions of 2012$)	**376.4**	**1,281.1**	**2,148.5**	**880.5**	**8,311.6**	**735.5**	**18.0**	**13,751.7**
Provincial Corporate Income Tax	0.0	0.0	0.0	252.5	3,487.8	0.0	0.0	3,740.3
Per Capita Share of Federal Corporate Income Tax	376.4	1,281.1	2,148.5	373.0	614.8	735.5	18.0	5,547.3
Royalties	0.0	0.0	0.0	255.0	4,209.0	0.0	0.0	4,464.0
				High Production Case				
Total Impact (millions of 2012$)	**275.8**	**938.8**	**1,574.6**	**478.9**	**5,373.3**	**539.1**	**13.2**	**9,193.8**
Provincial Corporate Income Tax	0.0	0.0	0.0	101.6	2,625.7	0.0	0.0	2,727.3
Per Capita Share of Federal Corporate Income Tax	275.8	938.8	1,574.6	273.4	450.6	539.1	13.2	4,065.5
Royalties	0.0	0.0	0.0	104.0	2,297.0	0.0	0.0	2,401.0

Source: The Conference Board of Canada.

Chapter 5: Conclusion

Canadian benchmark oil prices have lagged considerably behind their global peers in recent years. Ultimately this means that Canada is not getting the full fiscal and economic benefits associated with exploiting its non-renewable oil resources. In response, there has been growing interest in developing new oil transportation infrastructure in North America. There are currently four major pipeline projects under consideration that would move oil away from Western Canada if completed, including the TMEP.

If approved, the TMEP will generate economic and fiscal benefits. These benefits will occur in three key areas. The first is during the development stage of the Project, when the pipeline is being developed and built. The second comes during the operational period of the Project, with economic impacts associated with running and maintaining the pipeline. The last comes from the expectation that the TMEP will lead to higher netbacks for producers of heavy oil in Western Canada. All three of these effects will generate economic and fiscal impacts.

Development phase—Including the direct, supply chain, and induced effects, the spending during the development phase of the Project will support 58,037 person-years of employment, and $1.2 billion in federal ($646 million) and provincial ($568 million) government revenues. As the sites where the pipeline will be built, British Columbia and Alberta will account for the majority of these impacts. However, other provinces, and in particular Ontario, will benefit through supply chain effects and the redistribution of federal government revenues to the regions.

Operational phase—We estimate the operational impacts of the pipeline over its first 20 years of service under two scenarios, a minimum scenario based on the existing long-term contracts, and a maximum scenario based on the non-firm capacity in the pipeline being fully utilized. At a minimum, we expect pipeline operations to support 50,273 person-years of employment, and this figure rises to 65,184 if the non-firm capacity is fully utilized. In terms of fiscal effects, pipeline operations are expected to support between $2.5 and $3.3 billion in combined federal and provincial revenues, considerably above those from the development phase. British Columbia and Alberta enjoy the lion's share of these benefits; however, other provinces do benefit through supply chain effects and the redistribution of federal government revenues to the regions.

Higher netbacks—We estimate the fiscal impacts of higher netbacks under the three different cases developed by IHS. In the base case we expect these fiscal benefits to total $14.7 billion over the first 20 years of the pipeline's operations. The federal corporate income tax effects account for the largest share of these effects at $6.1 billion. The combined royalty and corporate income tax effect for Alberta is $8.2 billion, and for Saskatchewan it is $454 million. The cumulative fiscal effect ranges between $9.2 billion in the high production case and $13.8 billion in the low production case.

Table 8 summarizes the economic and fiscal impacts associated the TMEP using the minimum operating impacts and the base case for assessing the impact of higher netbacks. Between 2012 and 2037, the

Project is expected to generate 108,310 person-years of employment. As well, the Project will produce $18.5 billion of fiscal benefits over the same period.

Table 8. Summary of the Economic and Fiscal Impacts of the TMEP (cumulative effects, 2012-2037)

	Atlantic Canada	Quebec	Ontario	Other Prairies	Alberta	British Columbia	Territories	Canada
	Using Minimum Operational Effects and the Base Case for Higher Netbacks							
Employment effects (person-years)	**617**	**3,372**	**11,004**	**2,124**	**24,926**	**66,132**	**135**	**108,310**
Project development	289	1,402	4,659	1,099	14,632	35,864	92	58,037
Project operations	327	1,970	6,345	1,025	10,293	30,269	43	50,273
GDP effects (millions of 2012$)	**46.0**	**285.8**	**951.5**	**185.5**	**5,360.5**	**11,329.2**	**15.7**	**18,174.2**
Project development	21.7	120.1	408.6	98.5	1,402.4	2,789.1	11.2	4,851.7
Project operations	24.3	165.6	542.9	87.0	3,958.1	8,540.2	4.5	13,322.5
Fiscal Impact (millions of 2012$)	**564.0**	**1,920.1**	**3,277.7**	**1,030.5**	**9,577.3**	**2,086.5**	**26.6**	**18,482.7**
Project development	48.2	166.2	306.6	57.5	239.1	394.3	2.2	1,214.1
Project operations	104.0	352.1	620.1	111.1	469.3	887.3	4.7	2,548.6
Higher netbacks	411.8	1401.8	2351.0	861.9	8868.9	804.9	19.7	14,720.0

Source: The Conference Board of Canada.

Appendix A: Resume and Professional Qualifications of Glen Hodgson

Employment History

The Conference Board of Canada

Senior Vice-President and Chief Economist **–** November 2006 to present
Vice-President and Chief Economist **–** September 2004-November 2006

- Member of executive team.
- Lead a management group of seven directors and forty staff.
- Responsible for economic forecasting of the Canadian, provincial, metropolitan, U.S. and international economies, and for numerous economic analysis contracts annually.
- Also responsible for international development projects delivered for clients.
- Lead spokesman for the Conference Board via presentations, articles and media.

Export Development Canada (EDC)

Vice-President and Deputy Chief Economist **–** October 2001 to September 2004

- Co-led a group of approx. 55 staff (with six team leaders) analyzing and forecasting major global and Canadian economic trends and assessing economic, political, environmental and other international business risks.
- A lead spokesman for EDC via presentations, articles and media.

Vice-President, Policy and International Relations **–** 2000-2001
Director, Government and International Relations **–** 1998-2000
Director, Government Relations and Corporate Policy **–** 1994-1998

- Reporting to the President, directed a policy staff that grew progressively to eighteen.
- Responsible for many facets of EDC's business strategy and policy, and related domestic and international legislation and regulation.
- Managed the corporation's relationship with its stakeholders in Canada and internationally.

Department of Finance, Government of Canada

Senior Chief, International Finance and Development Division **--** 1993-1994

- Co-directed a group of twenty responsible for the Canadian Government's international financial priorities and interests (G-7 financial issues, export credits, debt rescheduling, foreign aid policy, multilateral financial institutions, etc.)
- Provided Budget advice on national defense, foreign aid and international finance.

Departmental Secretary, Deputy Minister's Office -- 1991-92

- Acted as Executive Assistant to the Deputy while directing a staff of 12.
- Helped to manage the Department's relationship with the Minister of Finance, his staff and with other departments and agencies
- Coordinated multiple Federal Budgets; developed the Department's Corporate Plan.

Chief, International Development Finance -- 1988-91

- Directed a group of seven responsible for: Canada's membership in the IMF, World Bank, EBRD and the other regional development banks; foreign aid budgetary and policy issues; and export financing issues.

Economist, International Programs Division -- 1982-84

- Responsible for country risk analysis, debt rescheduling, export and development financing.

International Monetary Fund

Advisor/Assistant to the Executive Director for Canada, Ireland and the Caribbean on the Board of Directors -- 1984-88

- Advisor to the Canadian Executive Director on IMF lending, policy and administration.
- Represented the Executive Director in IMF Board discussions and on country missions.

Education

Ph.D. Candidate in Economics (ABD), McGill University, 1981

M.A. in Economics, McGill University, 1981

B.A. (Honours), University of Manitoba, 1978

Publications – Over 200 publications; full list available separately upon request.

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Appendix C: Input/Output Models

Input/output (I/O) models are economic models that describe how goods and services flow through an economy. There are two key elements in an I/O model, geography and commodities. Commodities represent particular goods or services, and the I/O model encompasses information regarding which industries produce these commodities and how they are used; either as inputs into other industries, consumed domestically, or exported. The geography element tracks where production takes place, and how different commodities are traded across provincial and international boundaries.

One of the uses for I/O models is to calculate the economic impacts associated with different types of economic activity. Because the model describes how the supply chains work, we are able to “shock” the I/O model and observe how the impact feeds through the economy. “Shocks” are inputs into the model and can take different forms. For example, the effects of the TMEP’s operations in this report are measured using a “gross output” or revenue shock. Essentially we increase the revenues of the oil pipeline industry by a certain amount and observe the results. The shock associated with the development of the TMEP was implemented in a different way. We increased the demand for different types of commodities that will be used in the project, such as pipe, tanks, and construction labour.

The I/O model used in this analysis is produced and maintained by Statistics Canada. Statistics Canada updates the I/O tables used by the model annually as parts of the Canadian System of National Accounts (CSNA). The CSNA is a system of integrated statistical accounts consisting of four main components: input-output accounts (national and provincial), income and expenditure accounts (national and provincial), balance of payments and the financial and wealth accounts. The I/O tables cover all economic activities conducted in the market economies of each province and territory, encompassing persons, businesses, government and non-governmental (non-profit) organizations, and entities outside its jurisdiction that give rise to imports or exports (inter-provincially or internationally).

To compile the I/O accounts, Statistics Canada obtains source data from all relevant surveys as well as administrative sources such as tax records, professional and industry organizations, and non-government institutions every year for each province and territory. In the process of preparing statistical estimates, data from various sources are confronted, analysed by subject-matter experts and used to compile estimates that are consistent with all other estimates in the System and provide a valid and coherent statistical picture of the subject matter. Consistency is a key feature of the statistics produced by the Accounts.

The result is that Statistics Canada’s I/O model is the most comprehensive description of how economic activity flows through the Canadian economy. The model describes the flows for more than 700 different commodities and 300 different industries across all provinces and territories. The model solutions include both “open” results, which summarize the direct and indirect impacts of a shock, and “closed” results, which summarize the combined direct, indirect, and induced impacts. Key outputs from the model that can be used to describe the results of a shock include employment, GDP, labour income, gross output, and international trade. The results described here used Statistics Canada's 2009 I/O model, the most current available at the time of the analysis.

Key Assumptions

Although I/O models can be useful tools for understanding the economic impacts associated with particular projects, it is also important to understand that a number of assumptions are embedded in the results. The following section discusses some of these major assumptions.

Fixed Production Patterns

The tables that underlay the I/O model are based on the supply chain relationship in the Canadian economy at a fixed point in time; in this particular case 2009. As such, the model results do not factor in how things like changes in relative prices for different inputs, productivity, and technology can impact supply chains over time. As well, trade flows do not take into account external factors, such as changes in exchange rates, the emergence of new trading partners, or changes in trade policy.

This assumption is also pertinent in the discussion of the induced effects. The model assumes fixed consumption and savings patterns for consumers over time. In reality, spending and saving patterns are influenced by a variety of factors including economic circumstances and demographics. As a result, the farther you look forward in time using an I/O model the less likely it is that the model accurately describes future economic activity.

Lack of Supply Constraints

Another key assumption embedded in the I/O results is that there are no supply constraints on the economy. This means that the model results assume that all of the inputs needed to conduct the shock are readily available, and that the modelled project will not be competing with others for resources. In reality, if a project is of significant size it may lead to higher prices and/or wages as the new project will draws resources away from other activities.

This is particularly pertinent in the discussion of the induced effects. The induced effects assume that the people employed as a result of the direct and indirect effects would otherwise be unemployed, but at least some of them would likely find other employment, though their pay may be less. Thus, including the induced effects likely overstates the total economic effects; however, not including them would definitely understand the total economic effects.

Industry Homogeneity

I/O models typically assume that all firms within an industry are characterized by a common production process. In practical terms, the model reflects an industry average, thus Trans Mountain's operations and business practices are assumed to be the same as other oil pipeline operators such as Enbridge or TransCanada. If Trans Mountain's production structure is significantly different from the industry average than the economic impact results may be different from what is characterized here.

Industry homogeneity also assumes a constant return to scale for all businesses in an industry; in other words the model assumes a linear relationship between inputs and outputs. In practice, many industries experience at least some economies of scale, which means there is an optimal scale at which businesses should operate. Thus, in the model each extra dollar of revenue or investment is assumed to result in the same relative increase in economic activity. In reality, that may not be strictly true.

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Appendix C Direct Evidence of John J. Reed of Concentric Energy Advisors, Inc. to the National Energy Board

NATIONAL ENERGY BOARD

IN THE MATTER OF the *National Energy Board Act*, R.S.C. 1985, c. N-7, as amended, ("*NEB Act*") and the Regulations made thereunder;

IN THE MATTER OF the *Canadian Environmental Assessment Act*, S.C. 1992, c. 37, as amended, and the Regulations made thereunder;

AND IN THE MATTER OF an Application pursuant to Part III of the *NEB Act* by Trans Mountain Pipeline ULC as General Partner of Trans Mountain Pipeline L.P. (collectively "Trans Mountain") for a certificate of public convenience and necessity authorizing the construction and operation of the expanded Trans Mountain Pipeline System.

APPLICATION BY TRANS MOUNTAIN FOR A CERTIFICATE OF PUBLIC CONVENIENCE AND NECESSITY AUTHORIZING THE CONSTRUCTION AND OPERATION OF THE EXPANDED TRANS MOUNTAIN PIPELINE SYSTEM

November 30, 2013

DIRECT EVIDENCE OF JOHN J. REED

To: The Secretary
National Energy Board
444-7th Avenue S.W.
Calgary, AB T2P 0X8

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I. INTRODUCTION

Q1. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A1. My name is John J. Reed. My business address is 293 Boston Post Road West, Suite 500, Marlborough, Massachusetts 01752.

Q2. BY WHOM AND IN WHAT CAPACITY ARE YOU EMPLOYED?

A2. I am Chairman and Chief Executive Officer of Concentric Energy Advisors, Inc. ("Concentric"). Concentric is a management consulting firm specializing in financial and economic services to the energy industry.

Q3. PLEASE DESCRIBE YOUR PROFESSIONAL BACKGROUND AND EXPERIENCE.

A3. I have more than thirty-five years of experience in the North American energy industry. Prior to my current position with Concentric, I served in executive positions with various consulting firms and as Chief Economist with Southern California Gas Company, North America's largest gas distribution utility. I have provided expert testimony on financial and economic matters on more than 150 occasions before the National Energy Board ("NEB" or "Board"), the Federal Energy Regulatory Commission ("FERC"), provincial and state utility regulatory agencies, various state and federal courts, and before arbitration panels in Canada and the United States. A copy of my résumé and a listing of the testimony I have sponsored is included as Attachment A.

Q4. IN WHICH CASES HAVE YOU PREVIOUSLY TESTIFIED BEFORE THE BOARD?

A4. I have submitted evidence before the Board on behalf of the following parties in the following proceedings:

- Alberta-Northeast (GH-1-87)
- Alberta-Northeast (GH-2-87)
- Alberta-Northeast (GH-5-89)
- Independent Petroleum Association of Canada (RH-2-91)

- The Canadian Association of Petroleum Producers (RH-1-93)
- Maritimes & Northeast Pipeline (GH-6-96)
- Alliance Pipeline (GH-3-97)
- Maritimes & Northeast Pipeline (GH-3-2002)
- TransCanada PipeLines (RH-3-2004)
- Brunswick Pipeline (GH-1-2006)
- TransCanada PipeLines (RH-1-2007)
- Repsol Energy Canada (GH-1-2008)
- Maritimes & Northeast Pipeline (RH-4-2010)
- TransCanada PipeLines (RH-003-2011)
- Trans Mountain Pipeline (RH-001-2012)
- TransCanada PipeLines (RH-001-2013)
- NOVA Gas Transmission Ltd. Board File OF-Fac-Gas-NO81-2013-10 01

In addition to testifying, I have worked with numerous entities in the Canadian energy industry during my career, assisting them with various strategic, regulatory and toll-related issues.

Q5. ON WHOSE BEHALF ARE YOU SPONSORING EVIDENCE IN THIS PROCEEDING?

A5. I am sponsoring evidence on behalf of Trans Mountain Pipeline ULC ("Trans Mountain" or the "Company").

Q6. WHAT IS THE PURPOSE OF YOUR EVIDENCE?

A6. The purpose of my direct evidence is to address two major areas: 1) a review and assessment of whether the Trans Mountain Expansion Project ("TMEP" or the "Project") meets the Board's standards for economic and financial feasibility, which are important criteria for the determination of whether a project is in the public interest; and 2) an overview of the benefits of the Project, in terms of energy industry benefits and economic benefits.

Q7. WHAT INFORMATION CONTAINED IN THE APPLICATION HAVE YOU REVIEWED FOR THE DEVELOPMENT OF YOUR EVIDENCE?

A7. I have reviewed Volumes 1, 2 and 5B of the application. My review began with the chapters that included quantitative assessments of the benefits of the Project, including the studies prepared by The Conference Board of Canada ("Conference Board"), which has developed a report that evaluates the economic benefits of the Trans Mountain Project, and by IHS Global Canada Limited ("IHS"), which has developed a report that provides an independent assessment of the market for the products shipped on the Project, the supplies available to the Project, and oil industry benefits and impacts that are expected to result from the operation of the Project. I have also focused on the information prepared by TERA Environmental Consultants ("TERA"), which produced the Socio – Economic analysis included in the application.

II. EXECUTIVE SUMMARY

Q8. PLEASE SUMMARIZE THE CONCLUSIONS OF YOUR EVIDENCE.

A8. I have reviewed the Company's application, the requirements of Section 52 of the NEB Act, the Board's Filing Manual as well as precedent from past Board decisions, and have concluded that the Project is both economically and financially feasible and would result in substantial benefits both to the Western Canadian oil industry and to the Canadian, provincial and local economies. Regarding the economic and financial viability of the Project, my conclusions are:

- The market study developed by IHS provides convincing evidence that Western Canadian oil production will ensure more than adequate supplies of oil to support the Project over its operating life. According to the IHS study, even if all four of the major oil pipeline projects currently proposed in Western Canada are built, the market can fully absorb the new capacity, through production expansion, by approximately 2030.
- The potential for some level of under-utilization of the region's aggregate pipeline capacity during the 2017-2030 period does not indicate that the TMEP, or any of the other proposed projects, are not economically feasible. The TMEP provides a feasible and efficient means of addressing the asymmetrical risk of too much/too little capacity. Some level of optionality in capacity markets promotes economic efficiency, reflects the likelihood of

future additional demand and does not detract from the economic feasibility of the TMEP. The relative attractiveness of markets can change quickly, as supply and demand fundamentals shift. Having transportation infrastructure that accommodates shifts in market preferences creates value, by providing the option and ability to redirect flows as markets change.

- IHS estimates that in the base case, higher netback prices for heavy crude oil production will provide total producer benefits of $140 billion with $37 billion attributable to the market access provided by the TMEP for the forecast period (2017–2037).[1] In addition, the netback benefits attributed to the TMEP that are associated with the access provided to Asian markets are estimated at $8 billion over the forecast period. Therefore, total benefits attributable to TMEP are approximately $45 billion (all figures in $2012).[2]
- The Project will provide access to California, the U.S. Pacific Northwest and other Pacific Rim markets. The Pacific Rim includes some of the fastest growing oil markets in the world. The results of the IHS study also indicate that the netbacks calculated to California and other Pacific Rim markets are expected to remain at a premium to all other markets served by oil pipelines connected to Western Canadian oil production over the entire study period.
- The Project has received binding long-term commitments for 100 percent of the capacity reserved for firm service from 13 financially strong shippers. These contracts are a clear indication that the Project can reasonably be expected to be used at a high load factor. The take-or-pay provisions in the Transportation Service Agreements (“TSAs”) ensure that fixed charges will be paid over the first 15-20 years of operation. These contracts provide evidence that the market views the Project as necessary and economical.
- These contractual commitments, coupled with the strong credit rating of the Company’s parent, Kinder Morgan Energy Partners LP, and the fact that the Project is designed to respond to the needs of shippers in the evolving market for oil pipeline services, should make financing readily attainable.

The Project will help to realign Canada’s pipeline system with new market realities, resulting in numerous benefits to the Western Canadian oil industry, specifically:

- The Project alleviates concerns over inadequate capacity and minimizes apportionment by allowing shippers to execute long-term contracts for firm

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[1] Benefits attributable to TMEP equate to approximately 26 percent of the total estimated benefits for the major planned export pipeline capacity expansions.

[2] All figures in this evidence and all figures cited from the IHS and Conference Board studies are in constant $2012.

service, while also providing uncommitted land and Westridge Marine Terminal (“Dock”) shippers with greater access to spot capacity.

- The Project will create a higher-value pathway to California and other Pacific Rim markets, providing desired market diversification and, according to the IHS study, higher netbacks for Western Canadian heavy crude oil producers.
- Through enhanced access to California and other Pacific Rim markets, the Project offers producers an alternative to traditional North American markets and greater market optionality, thus reducing the likelihood of a recurrence of the price discounting of Canadian oil experienced over the past several years.
- The sizing of the Project to meet contractual demand while providing a reasonable level of uncommitted service promotes productive efficiency and limits the risk of underutilization; at the same time, the Project’s firm service contracts promote allocative efficiency by awarding capacity to the shippers who value it the most, and the contract provision allowing for capacity release into the secondary market ensures that capacity will continue to be allocated to those shippers that value it most on an ongoing basis throughout the Project’s life.

According to the Conference Board economic benefits study and the socio-economic impacts calculated by TERA in the Environmental and Socio-economic Assessment, the Project would also provide substantial macroeconomic benefits at the federal and provincial levels. Specifically, those benefits include:

- An estimated 58,037 person-years of employment during the development phase, and another 50,273 to 65,184 person-years of employment during the first 20 years of operation;
- Total estimated GDP effects in Canada between 2012 and 2037 ranging from $18 billion to $22 billion;
- Incremental government revenues from the construction and operation of the Project over the first 20 years of $3.76 billion to $4.52 billion;
- An additional $14.7 billion in income taxes and royalty payments at the federal and provincial level as a result of higher netbacks to oil producers; and
- Incremental property tax revenue of $25.3 million per annum in Alberta and British Columbia collectively.

III. <u>BOARD'S STANDARDS FOR EVALUATING ECONOMIC AND FINANCIAL VIABILITY OF THE PROPOSED PROJECT</u>

Q9. HOW HAS THE BOARD TRADITIONALLY ASSESSED THE ECONOMIC AND FINANCIAL VIABILITY OF A PROPOSED PROJECT?

A9. Section 52 of the NEB Act states that when considering an application for a certificate:

> [T]he Board shall have regard to all considerations that appear to it to be relevant, and may have regard to the following:
>
> (a) the availability of oil, gas or any other commodity to the pipeline;
> (b) the existence of markets, actual or potential;
> (c) the economic feasibility of the pipeline;
> (d) the financial responsibility and financial structure of the applicant, the methods of financing the pipeline and the extent to which Canadians will have an opportunity of participating in the financing, engineering and construction of the pipeline; and
> (e) any public interest that in the Board's opinion may be affected by the granting or the refusing of the application.

In practice, the Board's standard for determining if a project is economically feasible—criterion (c) above—has been the presentation of satisfactory evidence that criteria (a), (b) and (d) above have been met. In *Mackenzie*, the Board stated:

> The National Energy Board takes the following criteria into consideration when considering economic feasibility for facilities built under the *National Energy Board Act*:
>
> - the availability of markets for the gas flowing on the pipeline (will the gas be purchased?);
> - the availability of downstream pipeline capacity (will there be sufficient pipeline capacity to move the gas from the end of the [Project] to ultimate markets?);
> - the long-term gas supply which is available to the pipeline (is there sufficient gas to be transported?);
> - the contractual commitments underpinning the project (will the fixed cost component of the pipeline tolls be paid?); and

- the ability of the project to be financed (will investors fund the pipeline?).[3]

The Board's threshold criteria for economic feasibility are also reflected, in more abbreviated terms, in Guide A, Section A.3 of its Filing Manual, which states:

> The overall purpose for filing information on facility economics is to demonstrate that the applied-for facilities will be used, will be useful, and that demand charges will be paid...[4]

Q10. PLEASE EXPLAIN YOUR DISTINCTION BETWEEN FINANCIAL AND ECONOMIC VIABILITY.

A10. In my usage of these terms, "financial feasibility" refers to commercial matters and focuses on the Board's criteria regarding the ability of a project to be financed and whether a project's fixed charges are likely to be paid. Commercial matters include factors such as the fairness and efficiency of the tolling principles proposed and the contractual commitments that have been signed. The term "economic feasibility," as I have used it, addresses the justification and need for a project within an industry context and centers on the Board's criterion that a project be used and useful. Economic feasibility is dependent on whether adequate commodity supply exists, and whether there is market demand for a project, and examines the level of shipper support for a project.

Q11. ARE THERE OTHER STANDARDS USED BY THE BOARD TO EVALUATE THE ECONOMIC AND FINANCIAL VIABILITY OF A PROJECT?

A11. Yes. While not addressed in every proceeding, there are a number of other standards that the Board has applied in assessing the economic and financial feasibility of a proposed project. With regard to economic feasibility, the Board also commonly evaluates: (i) whether a project is consistent with the competitive context of the market, and (ii) whether a project has been sized correctly.

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3 NEB, Reasons for Decision, Volume 2, Chapter 7, GH-1-2004.

4 NEB Filing Manual, Guide A, Section A.3, p. 4A-62.

In terms of financial feasibility, the Board also has considered: (i) whether a project can be financed without relying on tolls that create cross-subsidization, (ii) the reasonableness of risk apportionment in the project's commercial terms, and (iii) the competitiveness of a project, and its effect on the market.

In certain cases, the Board has placed considerable weight on these factors. Therefore, in my evidence I have also addressed the Project in terms of each of these additional criteria.

IV. FINANCIAL VIABILITY OF THE PROJECT

Q12. HAS THE BOARD PREVIOUSLY RULED ON THE TOLLING PRINCIPLES PROPOSED FOR TMEP BY THE COMPANY?

A12. Yes. Unlike many other large proposed pipeline projects before the Board, TMEP has fully addressed all of the matters regarding Section IV of the *NEB Act* in a separate proceeding filed in 2012. In its May 16, 2013 decision, the Board found both the tolling principles and the terms and conditions in the Facilities Support Agreements ("FSAs") and TSAs pertaining to TMEP to be appropriate.[5]

Q13. ARE THE BOARD'S FINDINGS IN THE TMEP TOLLING PROCEEDING RELEVANT TO AN ASSESSMENT OF THE PROJECT'S FINANCIAL VIABILITY?

A13. I believe they are. While there are no open issues regarding the tolling principles or the terms and conditions of the FSAs and TSAs that the Company and its shippers have signed, it is appropriate to consider many of the Board's findings in that proceeding, since those matters relate to the financial feasibility of the Project. In the tolling proceeding, the Board found that: (i) the proposed tolling principles were just and reasonable as well as non-discriminatory; (ii) the terms and conditions of the FSAs and TSAs were appropriate; and, (iii) the open season process was fair and transparent.

[5] NEB, Reasons for Decision, RH-001-2012.

Q14. HOW DO THE APPROVED TOLLING PRINCIPLES SUPPORT THE FINANCIAL VIABILITY OF THE PROJECT?

A14. The Project's tolling principles have been designed so that an integrated, market-based set of tolls are applicable to all service on TMEP after it is expanded, and the tolling principles will be used for 20 years to derive predictable and stable tolls over the life of the TSAs. The tolling principles reflect the costs of the Project and were determined to be just and reasonable and to not create any unjust discrimination. Adherence to cost causation principles in toll treatment, and the avoidance of unjust discrimination, is viewed by the Board as a threshold criterion in assessing a project's economic and financial feasibility.[6]

Q15. HOW DO THE TERMS AND CONDITIONS IN THE FSAS AND TSAS SUPPORT THE FINANCIAL VIABILITY OF THE PROJECT?

A15. The terms and conditions in the FSAs and TSAs define the risk allocation between the Project sponsor and the shippers. In *Alliance*, the Board stated:

> In its application, Alliance declared itself to be "at-risk" with respect to any underutilization of the applied-for facilities… This fact addresses one potentially significant public interest consideration.[7]

I agree with the Board's assessment that risk apportionment is a significant public interest consideration.

The risk apportionment in the Project's FSA and TSA terms and conditions, which has already received Board approval, is reasonable and promotes productive efficiency. By sharing the costs associated with construction cost overruns and bearing the underutilization risk during the first 20 years of operations, the Company is "at-risk" and has an incentive to construct and operate the Project as cost-effectively as possible, while maintaining the high standards for constructing and operating the Pipeline outlined in the Company's Application. Thus, productive efficiency is strongly promoted.

---

6 NEB, Reasons for Decision, GH-001-2012, p. 41.
7 NEB, Reasons for Decision, GH-3-97, p. 13.

Q16. HOW DOES THE BOARD'S VIEW ON THE CONSISTENCY OF THE PROJECT'S UNDERPINNINGS WITH COMPETITIVE MARKET PRINCIPLES AFFECT ITS ANALYSIS OF THE FINANCIAL VIABILITY OF THE PROJECT?

A16. As I stated in Section III of my evidence, the Board often examines whether a proposed project was developed in a manner that was consistent with competitive market principles. In its decision in the Project's 2012 tolls proceeding, it was the Boards' view that the appropriateness of the open season process, the presence of alternative sources of transportation, and the fact that the tolling methodology was the result of arms-length negotiations between sophisticated parties have collectively mitigated any concerns that the Company was able to abuse market power or otherwise adversely affect competition in negotiating its tolling methodology. The Board's decision in the tolls proceeding should also provide assurance that the Project is financially viable.

Q17. IN ASSESSING A PROPOSED PROJECT'S FINANCIAL VIABILITY, IS IT THE BOARD'S PRACTICE TO CONSIDER OTHER COMPETING PROJECTS?

A17. While the Board sometimes considers the competitive framework in which a project is being proposed, it does not typically assess or consider the relative merits of competing projects. In *Keystone*, the Board stated:

> It was suggested by the CEP in final argument that the Board should consider the public interest broadly enough to review this application in comparison or conjunction with other proposed projects. The Board does not however have a practice of hearing facilities applications on a comparative basis and has, in the case of *Sable*, determined that it is not under a statutory obligation to hold comparative hearings.[8]

In other words, the Board does not have a practice of picking winners and losers. In assessing a project's economic and financial feasibility, the Board evaluates the effect that project would have on market competition and intervenes only in instances

8 NEB, Reasons for Decision, OH-1-2007, p. 14.

where competitive market forces may be unable to be effective. When no unreasonable adverse effect on competition is anticipated, it is the Board's view that the market should decide if the project is eventually built. The Board has reiterated this position on a number of occasions in past decisions. In *Keystone XL*, the Board stated:

> [I]n general, the public interest is served by allowing competitive forces to work, except where there are costs that outweigh the benefits.[9]

In *Mackenzie*, the Board stated:

> Our approval gives Mackenzie gas an opportunity to compete. Denial would block that opportunity indefinitely.[10]

As acknowledged in TMEP's application, the Project is one of a group of pipelines that are being proposed to meet the market's need for additional pipeline capacity. However, the financial feasibility of TMEP does not depend on the success or failure of any of those other projects, and the Board's past standards do not suggest that a comparison of the Project to those other projects is appropriate. The Project, and its shippers, are fully prepared to proceed once the Board has granted the necessary approvals, without regard to whether other competing projects move forward or not.

Q18. IS THE COMPANY'S SIZING OF THE PROJECT CONSISTENT WITH THE BOARD'S FINANCIAL VIABILITY STANDARDS?

A18. Yes, it is. The Project has been sized to meet contractual demand plus anticipated spot service. There is no unsold capacity other than the 20 percent of total nominal capacity that the Board deemed appropriate to reserve for non-firm or spot service, and virtually all of the TMEP's firm capacity is subscribed from the date of the initiation of service of the Project. The need for and sizing of the Project is not dependent on any forecasted market developments or future events.

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9 NEB, Reasons for Decision, OH-1-2009, p. 32.

10 NEB, Reasons for Decision, Volume 2, Chapter 7, GH-1-2004.

Q19. PLEASE COMMENT ON THE LIKELIHOOD THAT THE PROJECT'S FIXED COSTS WILL BE PAID.

A19. In light of all of the facts referred to in this section of my evidence, I have concluded that there is a very high likelihood that the fixed charges on TMEP will be paid over the first 20 years of service. The Project is consistent with the new market for oil pipeline services in that it offers firm transportation under long-term contracts while still offering spot service at a premium to the firm service. The project is also responsive to shipper requests for long-term toll stability and predictability. A very high level of support for the Project from 13 financially strong shippers has been demonstrated by the long-term FSAs and TSAs that have been executed, and by expressions of interest in spot service. In total, these facts fully support a conclusion that the Project's fixed charges will be paid.

Q20. WHAT HAVE YOU CONCLUDED WITH REGARD TO WHETHER THE PROJECT IS LIKELY TO BE FINANCEABLE?

A20. As discussed in TMEP's application, Trans Mountain Pipeline ULC expects to finance the Project with equity supplied by the parent company Kinder Morgan Energy Partners, L.P. ("KMP") and with corporate debt sourced from Canadian and U.S. lenders. KMP expects to rely on a balanced capital structure (50% debt and 50% equity), and to be able to secure an investment-grade rating for the long-term debt. This is consistent with the fact that KMP had its issuer rating of BBB confirmed by Fitch earlier this year.[11] Based on the strength of the FSAs and TSAs that credit-worthy shippers have signed, and on the approved tolling methodology, it is reasonable to conclude that the Project is highly financeable. Furthermore, based on my understanding of the Project's economics, risk apportionment and the level of shipper support, I have concluded that the Project will be able to secure capital on reasonable terms, and be financially feasible.

[11] KMP's current credit rating for long-term corporate debt is: BBB (stable) at Standard & Poor's Ratings Services; Baa2 (stable) at Moody's Investors Service Inc.; and, BBB (stable) at Fitch, Inc.

V. *ECONOMIC VIABILITY OF THE PROJECT*

Q21. IN ASSESSING THE ECONOMIC VIABILITY OF PIPELINE PROJECTS, WHAT CRITERIA DOES THE BOARD TAKE INTO CONSIDERATION?

A21. The Board has commented expansively in past decisions on the criteria to use when considering the economic feasibility of new pipeline projects. In *Alliance*, the Board stated:

> As noted in Chapter 1, this assessment includes an evaluation of: (i) the availability of long-term gas supply, (ii) the long-term outlook for gas markets, (iii) the contractual commitments underpinning the proposal, and (iv) project financing.[12]

In addition, Section A.3 of the NEB's Filing Manual states that filing information related to economic viability should demonstrate that the applied-for facilities will be used, will be useful, and that fixed charges will be paid and that sufficient funds will be available for abandonment requirements.[13]

Q22. DO THE LONG TERM CONTRACT COMMITMENTS THAT TMEP HAS ENTERED INTO PROVIDE ASSURANCE THAT THE PIPELINE WILL BE USED AT A HIGH LOAD FACTOR[14]?

A22. Yes. The Project has firm commitments of approximately 708,000 bpd from 13 shippers that have signed 15 or 20 year contract commitments that underpin the project. These contracts are a clear demonstration that the project can reasonably be expected to be utilized at a high load factor. For example, a contract for 50,000 bpd for 20 years could result in a take or pay commitment of approximately $1.5 billion dollars for the firm shipper. It can reasonably be assumed that such a commitment by a shipper is not going to be made lightly or without a plan to ship oil. As represented in the Project's tolling proceeding, there is strong shipper support for

[12] NEB, Reasons for Decision, GH-3-97, p. 12.

[13] Funding requirements for pipeline abandonment is currently before the Board as part of its Land Matters Consultation Initiative ("LMCI"). An oral hearing is scheduled for January 2014 to consider the mechanisms proposed by federally regulated pipeline companies to set-aside and collect funds to cover the cost of future abandonment projects. Trans Mountain has filed an application for approval of its proposed set aside and collection mechanism in the LMCI proceeding.

[14] A high load factor pipeline is a pipeline that is used at a high rate on a relatively constant basis.

the Project with contractual commitments for capacity. Those commitments are held by a large number of financially strong shippers.

As noted by the Board in *Alliance*:

> The Board is also of the view that the financial commitments that shippers have made to pay $8.2 billion in demand charges on the Alliance system over the first 15 years of operation provides a powerful incentive for shippers to acquire adequate gas supplies. These companies, backed by their lenders, have made expert determinations that they will have access to adequate gas supplies in order to utilize their capacity entitlements on the Alliance Project.[15]
>
> ***
>
> The financial commitments of the Alliance shippers to the Project provide strong evidence that the market will be adequate. The Board recognizes the shippers' business expertise and their confidence that the market opportunities merit the investments to which they have committed.[16]

The same conclusion can reasonably be drawn from the facts that are presented in this application for the TMEP. The firm shipper commitments are strong indications that there is a need for the Project and that it is economically feasible.

Q23. WILL THE PROJECT HAVE ACCESS TO LONG TERM SUPPLY?

A23. Yes. As noted in the report developed by IHS and sponsored by Mr. Kelly, even if all four major new pipelines[17] that are currently proposed are built, the market can fully absorb the new capacity over time through production growth. In addition, the Project is fully consistent with the competitive context of the market as discussed below. Shippers want access to multiple markets and see a benefit in the flexibility of being able to go to a market that offers the highest netback at any point in time, especially when market dynamics are unpredictable. Based on the analysis completed by IHS, there is a potential for some level of under-utilization of the region's aggregate pipeline capacity during the 2017-2030 period, if all proposed projects

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15 NEB, Reasons for Decision, GH-3-97, p. 19.

16 *Ibid*, at 26.

17 These four projects are the TMEP, Northern Gateway, Keystone XL, and Energy East.

proceed as planned. However, that does not indicate that TMEP, or any of the other proposed projects, are not economically feasible.

Q24. WHAT HAS BEEN THE BOARD'S VIEW WHEN IT COMES TO THE POSSIBLE UNDER-UTILIZATION OF PIPELINE CAPACITY?

A24. In its decision for *Keystone XL*, the Board was clear that in the development of pipelines both current and future requirements for transportation service must be taken into consideration. The Board stated that:

> The Board is of the view, however, that prudent design must consider both the current and future requirements for transportation service over the life of a Project to achieve the objective of efficiency. The Board is satisfied that the Keystone XL Pipeline, as proposed, reflects a reasonable balance of both the current and anticipated requirements of shippers over the longer term, given the supply potential of the WCSB and the size of the USGC market.[18]

These views are also relevant to the Board's evaluation of the current set of proposed oil pipelines, including TMEP. Some level of optionality in capacity markets promotes economic efficiency, reflects the likelihood of future additional demand and does not detract from the economic feasibility of the Project.

Q25. WHY IS THE POTENTIAL FOR SOME UNDERUTILIZED PIPELINE CAPACITY NOT AN INDICATION THAT ONE OR MORE OF THE PROPOSED PIPELINES IS NOT NEEDED?

A25. The balance between production and take-away capacity shown in the IHS study indicates that production is expected to grow to meet the full take-away capacity that is built, and that even if all proposed pipeline projects proceed as planned, the new capacity will be fully absorbed by 2030. In the intervening 10 years or so, the new capacity provided by these pipelines will promote market competition and higher netbacks to producers and will provide producers with the opportunity to develop new supply areas confidently. The IHS analysis in which all four large pipeline development projects come on-line by 2018 is not an actual forecast of pipeline

[18] NEB, Reasons for Decision, OH-1-2009, p. 18.

capacity, rather, it is a simplifying assumption made by IHS in order to estimate the netback benefits of the Project.

As seen in the time period from 2011 to present, insufficient pipeline capacity in the market can result in severe price discounting for Western Canadian crude supplies. IHS has estimated that in 2012 inadequate pipeline access for Alberta producers led to large price discounts for Canadian crude, which, in aggregate, reduced producer revenues by between $15 and $19 billion. Those foregone producer revenues should be compared against the much lower costs to shippers of holding some excess capacity. For example, using the lower end of this range, one year of lost revenues ($15 billion) is roughly equivalent to over 12 years of fixed toll charges on TMEP. Given that highly asymmetrical cost/benefit relationship, producers can be seen as making a rational economic decision by committing to TMEP and other projects on an unconditional basis, even if some excess capacity may result if all projects are developed as planned and on schedule. In addition, the Board's public interest considerations should take into account a new dynamic in oil markets. The need for new pipeline facilities is not simply the difference between projected supply and current take-away capacity. The market also needs: i) flexibility; ii) diversity of market access; iii) the ability to manage risk associated with competing in multiple markets; and iv) the ability to manage development and operational risk.

Q26. **PLEASE EXPLAIN HOW THESE ADDITIONAL ISSUES CONTRIBUTE TO THE NEED FOR NEW PIPELINE CAPACITY.**

A26. As discussed in the IHS study, Canadian crude production has historically relied on refining markets in Canada, the U.S. Midwest the Pacific Northwest, which have been accessed by a relatively small number of pipelines with dedicated markets. However, the significant expansion of Western Canadian crude production, combined with the increase in U.S. crude production and relatively stable refining demand, has led to a new market structure in which producers have sought access to an expanded set of market options for their production, and to transportation infrastructure which can access those markets. In order to accommodate these demands, the Canadian oil pipeline network needs to be reconfigured to go beyond its traditional role of providing crude supply to refineries in the interior of the continent, and also provide access to tidewater to achieve greater market reach.

The development of more of a "portfolio" approach to marketing also reflects the fact that different markets offer significantly different netbacks to producers, and that the relative attractiveness of markets can change quickly as supply and demand fundamentals shift. A portfolio approach to marketing requires that the transportation infrastructure accommodate shifts in market preferences, which in turn creates value through having the option and ability to redirect flows as markets change. The willingness of producers to commit to take-or-pay fixed charges for pipeline capacity to multiple markets makes economic sense when viewed in this context, and providing that optionality enables Canadian producers and resource owners to maximize the value they derive from oil production.

Shippers also recognize that there are risks that some projects may not be developed as planned or on schedule, and that even after commercial operation is achieved, some amount of capacity may not be fully available at all times.

All of these facts contribute to the demand for additional capacity and justify the economies of holding and paying for capacity that may not be used every day of the year.

Q27. **IN ADDITION TO THE SIGNED AGREEMENTS FOR FIRM SERVICE ON THE PROJECT, ARE THERE REASONS TO BELIEVE THAT SPOT SERVICE WILL ALSO CONTRIBUTE TO THE ECONOMIC VIABILITY OF THE PROJECT?**

A27. Yes. As compared to Gulf Coast, Midwestern or Eastern markets, TMEP will provide a higher-value pathway for spot volumes because it will provide access to the California and other Pacific Rim markets. As noted in the IHS report, the netback price for crude delivered to Asia or California markets is expected to be higher than the value of supplies delivered to U.S. Gulf Coast markets. Therefore, the value of spot service on TMEP can reasonably be expected to be higher than on other pipelines which access lower value markets, assuming that sufficient supplies will be shipped on TMEP. The availability of spot service on TMEP, and its economic advantage over competing routes, can be expected to contribute to the economic feasibility of the Project.

Q28. BASED ON THE FACTS DISCUSSED ABOVE, DOES THE PROJECT MEET THE BOARD'S STANDARDS FOR CONCLUDING THAT A PROJECT IS ECONOMICALLY FEASIBLE?

A28. Yes it does. TMEP is highly likely to be used and useful and it should be expected to operate at a high load factor. The Project is fully consistent with the Board's criteria for assessing economic feasibility, and consistent with the new market dynamics regarding the need for pipeline transportation optionality and flexibility.

VI. BENEFITS OF THE PROJECT

Q29. BRIEFLY DISCUSS THE OVERALL COMMERCIAL AND ECONOMIC BENEFITS OF THE PROJECT.

A29. TMEP provides significant benefits to Canada and will help realign Canada's pipeline system with new market realities. The Project offers economic benefits to the Western Canadian oil industry and to the federal government, the provinces and local communities through which the expanded pipeline will run. Those benefits have been quantified in reports provided by the Conference Board, IHS and TERA.

Q30. PLEASE SUMMARIZE THE PROJECT BENEFITS.

A30. The Project will provide the following benefits to WCSB oil producers and to federal, provincial and local governments: 1) enhanced quality and value of service for the Project's firm shippers; 2) enhanced access to California and other Pacific Rim markets, providing essential market diversification for Canadian oil producers; 3) higher prices/netbacks to Canadian oil producers as quantified by IHS; 4) the reduction in the likelihood of recurring price discounts for Canadian crude, based on the existence of paths to multiple markets, and flexibility to target the highest netback markets; 5) enhancement in secondary market competition to serve uncommitted volumes; 6) promotion of competition among oil pipelines; 7) increased flexibility and optionality in the entire oil pipeline transportation system; 8) the promotion of economic efficiency in pipeline transport markets (both productive and allocative); and 9) macroeconomic benefits in local, provincial and federal economies.

Q31. PLEASE DISCUSS HOW THE PROJECT WILL ENHANCE THE QUALITY AND VALUE OF SERVICE TO ALL SHIPPERS.

A31. Currently, with the exception of capacity reserved for the Firm 50 Dock shippers,[19] the Trans Mountain Pipeline has inadequate capacity to meet the demands of its Dock and land shippers. The Pipeline experiences substantial apportionment and over-nominations monthly, and has for several years. This has been a substantial problem for land shippers because they cannot secure committed capacity on the pipeline and therefore cannot have any assurance of securing service to their pipeline-connected refineries and terminals. This is also a significant problem for Dock shippers because they have to bid monthly premiums significantly in excess of the pipeline toll to secure capacity on the pipeline.[20] Collectively, for land and Dock shippers, the existing Trans Mountain system is unable to provide the level of predictability and certainty that the market needs (except for Firm 50 shippers).

Through the execution of the FSAs and TSAs, the committed shippers will be able, once the Project has been completed, to gain firm access to capacity for 15 to 20 years, which will essentially eliminate the apportionment on Trans Mountain that these shippers have faced. Uncommitted land shippers will have access to the majority of the remaining spot capacity and an opportunity to access additional capacity through the secondary market. Uncommitted Dock shippers will have access to more capacity than is currently available and also have the opportunity to access the secondary market. The Project will facilitate shippers' ability to arrange long-term business with confidence since under the terms of the contracts, shippers will have stable and predictable tolls for 20 years. Similarly, shippers will have more capacity options available with the Project through spot transactions, enhancing the quality and value of the capacity for all shippers. These improvements in the quality,

[19] NEB, Reasons for Decision, RH-2-2011.
[20] Bid premiums totaled $163 million in 2012.

reliability and availability of transportation service will improve the functionality and efficiency of the market.

Q32. PLEASE DESCRIBE HOW THE TRANS MOUNTAIN PROJECT ENHANCES MARKET DIVERSIFICATION FOR CANADIAN OIL PRODUCERS.

A32. As discussed earlier in this evidence, in the Trans Mountain Expansion Application and in the evidence of IHS, the primary purpose of the Project is to provide additional needed transportation capacity to deliver growing oil production to West Coast and offshore markets. Currently, Canadian oil is exported almost exclusively to U.S. markets. With U.S. oil production increasing, developing another market for Canadian oil is vital to ensuring that Canadian oil producers will receive full value for their production and, in turn, ensures that Canadians will receive maximum benefits from the development and sale of these natural resources. The Project provides producers with the opportunity to market their products to offshore markets, and at the same time, provides a price lift for all Canadian oil producers with the creation of a new and higher-value outlet for Canadian oil. With the ability to sell Canadian oil to offshore markets, shippers have the opportunity to reach the most attractive markets through firm and spot service that is competitively and predictably priced. As is true for virtually all commodity markets, the elimination of binding constraints (which can be logistical, contractual, and financial) on the ability of products to reach the highest value markets produces economic gains for producers, eliminates price distortions that can otherwise lead to inefficient use of the commodity, and helps to promote economically efficient investment decisions for producers and consumers.

Q33. PLEASE DISCUSS THE PROJECT BENEFITS OF HIGHER PRICES/NETBACKS TO ALL CANADIAN OIL PRODUCERS.

A33. Oil is actively traded in large, highly liquid multinational markets in which arbitrage opportunities are quickly exploited such that “the law of one price” prevails. In such markets, prices are established by the economics of the marginal supplier and the marginal consumer. Infrastructure developments which improve the efficiency of the market or economically remove constraints, increase the total economic welfare of all participants. By providing greater access for Canadian producers to a large, valuable market that is not easily accessible with the current infrastructure, the Project allows the entire Canadian producer community to profit from higher prices. In this market, relieving delivery constraints to a higher-value market is functionally equivalent to a sudden rise in demand from a large new market, lifting prices for producers that would otherwise be constrained in reaching the higher-value market. The IHS study estimated the effects that the Project's operation will have on producer netbacks in the WCSB and concluded that development of the Project, along with other planned major pipelines, will provide higher oil prices overall as compared to a Reference scenario in which these projects are not built. In its Expansion Scenario, IHS estimates that producer revenue benefits attributable to all the planned major pipelines can be expected to be $140 billion through 2037. Since TMEP represents about 26 percent of the assumed capacity additions, the estimated benefits attributable to the market access provided by TMEP equates to approximately $37 billion. In addition, the netback benefits attributed to TMEP that are associated with the access provided to Asian markets are estimated at $8 billion over the forecast period, resulting in total benefits attributable to TMEP of approximately $45 billion.

Q34. **HOW WILL THE PROJECT PROMOTE COMPETITION AMONG PIPELINES?**

A34. As noted by the Board in past decisions, the public interest is best served by allowing competitive forces to work. The Project promotes competition by giving shippers enhanced options for marketing their products and as noted above, provides broader market access by not only allowing shippers the ability to access the North American market, but also the growing Asian market. As noted by the Board in the *Keystone XL* Pipeline Decision:

> Moreover, the Board is of the view that all western Canadian producers are likely to benefit from the Keystone XL Pipeline over the longer term, through broader market access, greater customer choice and efficiencies gained through competition among pipelines.[21]

[21] NEB, Reasons for Decision, OH-1-2009, p. 33.

TMEP provides these same benefits to the market by creating new capacity for producers and enabling a greater level of competition among pipelines for uncommitted production.

Q35. HOW WILL THE PROJECT ENHANCE SECONDARY MARKET COMPETITION TO SERVE UNCOMMITTED VOLUMES?

A35. As noted in Section 2.5 of the Application, the terms of the firm TSAs require shippers to pay for the capacity whether or not it is used. As permitted under the terms of the TSAs, shippers are able to resell or assign any capacity that they are not using through secondary market transactions. That available capacity, competing against the 20% of capacity reserved for spot shippers, other pipeline capacity and rail options, will contribute to a competitive secondary market for transportation capacity. The availability of this market will enhance service to uncommitted spot shippers. Without the expanded firm services enabled by the Project, this level of competition in the secondary market would not be possible.

Q36. WILL THE DEVELOPMENT OF THE PROJECT PROVIDE FOR THE EFFICIENT ALLOCATION OF AVAILABLE CAPACITY?

A36. Yes it will. The efficient allocation of capacity, or assigning resources to their highest value use ("allocative efficiency"), is an economic benefit that is realized by the Project and is an objective that the Board has often noted for the regulation of pipelines. Under the Project's contracts, capacity has been awarded to shippers that value it the most, through an open, transparent and non-discriminatory open season process. Thus, in the first instance, the capacity rights have been allocated to those shippers who most highly value the capacity. As discussed, the terms of the contracts also allow shippers to trade their rights on a short or longer-term basis on the secondary market. This will ensure that capacity is allocated to shippers who most highly value it on an ongoing basis during the lifetime of the Project. Therefore, allocative efficiency will be improved through the Project's firm service structure, its expansion of the secondary market, and its reliance on an integrated and consistent set of market-based tolls.

Q37. **HOW WILL THE PROJECT'S NEW TOLLING STRUCTURE IMPROVE ALLOCATIVE EFFICIENCY?**

A37. Trans Mountain's existing tolls are an unusual mix of cost-based tolls, market-based tolls and rebates to shippers that were developed to deal with highly-constrained access to the Dock within a cost-based regulatory paradigm. These tolls do not provide a consistent, predictable or efficient price signal for firm and spot service on the pipeline, and have led to a contentious and cumbersome nomination and apportionment process. The new tolling principles, which are enabled by the simultaneous expansion of the pipeline and movement to a greater reliance on firm contracted service, will result in a consistent and efficient price signal to all market participants and help to ensure that shippers which most highly value the service will receive it.

Q38. **DOES THE PROJECT ALSO PROMOTE PRODUCTIVE EFFICIENCY BY PROVIDING THE RIGHT INCENTIVES TO REDUCE THE COST OF MEETING THE MARKET'S NEEDS?**

A38. Yes, it does. The Board-approved terms of the FSAs and TSAs provide effective and equitable risk sharing for construction cost changes, and the fixed toll structure provides strong protection for all shippers regarding toll escalation after commercial operation is achieved. In addition, the Project has been sized to meet the contracted demand and provide a reasonable level of uncommitted service, so that there is very little risk of underutilized capacity. Taken together, these features clearly promote productive efficiency, which the Board has also recognized as a goal of effective regulation.

Q39. DOES THE PROJECT PROVIDE MACROECONOMIC BENEFITS TO THE FEDERAL, PROVINCIAL, AND LOCAL ECONOMIES.

A39. Yes, the macroeconomic benefits of the Project will be substantial. As discussed in the Conference Board report, total benefits during the development phase of the Project support 58,037 person-years of employment, while the first 20 years of the Project's firm service operation supports 50,273 person-years of employment, plus an additional 14,911 person-years of employment if all spot capacity is utilized. The Conference Board has also estimated that incremental government revenues from spending on Project development and operations for the first 20 years range from $3.76 billion to $4.52 billion, depending on the level of spot service utilization.[22] TERA has also estimated that the Project will produce additional property tax benefits of approximately $3.4 million (a 116% increase) annually in Alberta and $23.2 million (a 101% increase) annually in BC. Total fiscal impacts associated with producers' higher netbacks, including income tax revenues and royalty payments are estimated to be $14.7 billion. Finally, total GDP effects from the construction and operation of the Project in Canada between 2012 and 2037 are estimated to range from $18 billion (with long-term contract volumes) to $22 billion (with spot volumes), which does not include the potential impact on GDP of higher netbacks to producers.[23] Clearly, the macroeconomic benefits are a multiple of the Project's costs and will be felt throughout the local, provincial and federal economies and governments.

VII. CONCLUSIONS

Q40. PLEASE SUMMARIZE THE CONCLUSIONS OF YOUR DIRECT EVIDENCE.

A40. The TMEP Application fully meets and conforms to the standards the Board has established for finding that a proposed project is financially and economically feasible. In addition, the Project is fully consistent with the market's preferences for a new market-based structure for service on TMEP and on oil pipelines generally. While the Board's decision in the TMEP tolling principles case recognized many of these benefits, they will only become possible when the pipeline is in operation, so the public interest consideration here should take these benefits into account. The Project also provides extensive benefits to Canadians across the country, including producers, residents of the areas through which the pipeline crosses, suppliers in many provinces, local, provincial and federal governments and the overall Canadian economy. The Project allows Canada to maximize the benefits it derives from the development of natural resources, and provides a feasible and efficient means of

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22 All Conference Board references are noted in 2012 dollars.

23 Expansion of the Trans Mountain Pipeline: Understanding the Economic Benefits for Canada and its Regions, Conference Board of Canada, Table 6, at 42.

addressing the asymmetrical risk of too much/too little capacity. TMEP's development does not hinge on the success or failure of any other planned oil pipeline projects; the shipper commitments are not contingent on what happens with other projects, and shippers have provided clear and convincing support for the development of this expanded path to high-value markets. The Board can, and should, place considerable weight on the willingness of 13 major producers and the Project sponsor to underwrite the cost of this project for up to 20 years. Taken together, I believe that these facts provide a compelling case for concluding that the Project is financially and economically feasible, and highly beneficial.

Q41. DOES THIS CONCLUDE YOUR PREPARED EVIDENCE?

A41. Yes.

John J. Reed
Chairman and Chief Executive Officer

John J. Reed is a financial and economic consultant with more than 35 years of experience in the energy industry. Mr. Reed has also been the CEO of an NASD member securities firm, and Co-CEO of the nation's largest publicly traded management consulting firm (NYSE: NCI). He has provided advisory services in the areas of mergers and acquisitions, asset divestitures and purchases, strategic planning, project finance, corporate valuation, energy market analysis, rate and regulatory matters and energy contract negotiations to clients across North and Central America. Mr. Reed's comprehensive experience includes the development and implementation of nuclear, fossil, and hydroelectric generation divestiture programs with an aggregate valuation in excess of $20 billion. Mr. Reed has also provided expert testimony on financial and economic matters on more than 150 occasions before the FERC, Canadian regulatory agencies, state utility regulatory agencies, various state and federal courts, and before arbitration panels in the United States and Canada. After graduation from the Wharton School of the University of Pennsylvania, Mr. Reed joined Southern California Gas Company, where he worked in the regulatory and financial groups, leaving the firm as Chief Economist in 1981. He served as executive and consultant with Stone & Webster Management Consulting and R.J. Rudden Associates prior to forming REED Consulting Group (RCG) in 1988. RCG was acquired by Navigant Consulting in 1997, where Mr. Reed served as an executive until leaving Navigant to join Concentric as Chairman and Chief Executive Officer.

REPRESENTATIVE PROJECT EXPERIENCE

EXECUTIVE MANAGEMENT

As an executive-level consultant, worked with CEOs, CFOs, other senior officers, and Boards of Directors of many of North America's top electric and gas utilities, as well as with senior political leaders of the U.S. and Canada on numerous engagements over the past 25 years. Directed merger, acquisition, divestiture, and project development engagements for utilities, pipelines and electric generation companies, repositioned several electric and gas utilities as pure distributors through a series of regulatory, financial, and legislative initiatives, and helped to develop and execute several "roll-up" or market aggregation strategies for companies seeking to achieve substantial scale in energy distribution, generation, transmission, and marketing.

FINANCIAL AND ECONOMIC ADVISORY SERVICES

Retained by many of the nation's leading energy companies and financial institutions for services relating to the purchase, sale or development of new enterprises. These projects included major new gas pipeline projects, gas storage projects, several non-utility generation projects, the purchase and sale of project development and gas marketing firms, and utility acquisitions. Specific services provided include the development of corporate expansion plans, review of acquisition candidates, establishment of divestiture standards, due diligence on acquisitions or financing, market entry or expansion studies, competitive assessments, project financing studies, and negotiations relating to these transactions.

LITIGATION SUPPORT AND EXPERT TESTIMONY

Provided expert testimony on more than 150 occasions in administrative and civil proceedings on a wide range of energy and economic issues. Clients in these matters have included gas distribution utilities, gas pipelines, gas producers, oil producers, electric utilities, large energy consumers, governmental and regulatory agencies, trade associations, independent energy project developers, engineering firms, and gas and power marketers. Testimony has focused on issues ranging from broad regulatory and economic policy to virtually all elements of the utility ratemaking process. Also frequently testified regarding energy contract interpretation, accepted energy industry practices, horizontal and vertical market power, quantification of damages, and management prudence. Has been active in regulatory contract and litigation matters on virtually all interstate pipeline systems serving the U.S. Northeast, Mid-Atlantic, Midwest, and Pacific regions.

Also served on FERC Commissioner Terzic's Task Force on Competition, which conducted an industry-wide investigation into the levels of and means of encouraging competition in U.S. natural gas markets and served on a "Blue Ribbon" panel established by the Province of New Brunswick regarding the future of natural gas distribution service in that province.

RESOURCE PROCUREMENT, CONTRACTING AND ANALYSIS

On behalf of gas distributors, gas pipelines, gas producers, electric utilities, and independent energy project developers, personally managed or participated in the negotiation, drafting, and regulatory support of hundreds of energy contracts, including the largest gas contracts in North America, electric contracts representing billions of dollars, pipeline and storage contracts, and facility leases.

These efforts have resulted in bringing large new energy projects to market across North America, the creation of hundreds of millions of dollars in savings through contract renegotiation, and the regulatory approval of a number of highly contested energy contracts.

STRATEGIC PLANNING AND UTILITY RESTRUCTURING

Acted as a leading participant in the restructuring of the natural gas and electric utility industries over the past fifteen years, as an adviser to local distribution companies, pipelines, electric utilities, and independent energy project developers. In the recent past, provided services to most of the top 50 utilities and energy marketers across North America. Managed projects that frequently included the redevelopment of strategic plans, corporate reorganizations, the development of multi-year regulatory and legislative agendas, merger, acquisition and divestiture strategies, and the development of market entry strategies. Developed and supported merchant function exit strategies, marketing affiliate strategies, and detailed plans for the functional business units of many of North America's leading utilities.

PROFESSIONAL HISTORY

Concentric Energy Advisors, Inc. (2002 – Present)
Chairman and Chief Executive Officer

CE Capital Advisors (2004 – Present)
Chairman, President, and Chief Executive Officer

Navigant Consulting, Inc. (1997 – 2002)
President, Navigant Energy Capital (2000 – 2002)
Executive Director (2000 – 2002)
Co-Chief Executive Officer, Vice Chairman (1999 – 2000)
Executive Managing Director (1998 – 1999)
President, REED Consulting Group, Inc. (1997 – 1998)

REED Consulting Group (1988 – 1997)
Chairman, President and Chief Executive Officer

R.J. Rudden Associates, Inc. (1983 – 1988)
Vice President

Stone & Webster Management Consultants, Inc. (1981 – 1983)
Senior Consultant
Consultant

Southern California Gas Company (1976 – 1981)
Corporate Economist
Financial Analyst
Treasury Analyst

EDUCATION AND CERTIFICATION

B.S., Economics and Finance, Wharton School, University of Pennsylvania, 1976
Licensed Securities Professional: NASD Series 7, 63, 24, 79 and 99 Licenses

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BOARDS OF DIRECTORS (PAST AND PRESENT)

Concentric Energy Advisors, Inc.
Navigant Consulting, Inc.
Navigant Energy Capital
Nukem, Inc.
New England Gas Association
R. J. Rudden Associates
REED Consulting Group

AFFILIATIONS

American Gas Association
Energy Bar Association
Guild of Gas Managers
International Association of Energy Economists
National Association of Business Economists

New England Gas Association
Society of Gas Lighters

ARTICLES AND PUBLICATIONS

"Maximizing U.S. federal loan guarantees for new nuclear energy," *Bulletin of the Atomic Scientists* (with John C. Slocum), July 29, 2009
"Smart Decoupling – Dealing with unfunded mandates in performance-based ratemaking," *Public Utilities Fortnightly*, May 2012

Appendix D Notice Pursuant to Section 87(1) of the *National Energy Board Act* for BC and Alberta

TRACT:

TRANS MOUNTAIN PIPELINE L.P.by the General Partner TRANS MOUNTAIN ULC (“Trans Mountain”)

NOTICE PURSUANT TO SECTION 87(1) OF THE NATIONAL ENERGY BOARD ACT PROVINCE OF ALBERTA

TO: ●

being the registered owner(s) (the “**Owner**”) of the lands described as follows (the “**Land**”):

(For details on land description, see Schedule “A” attached to and forming part of this Notice)

AND TO: ●

being other persons, as far as can be ascertained, interested in the said Land

Trans Mountain hereby gives notice of the following:

1. <u>Description of Lands Required for Pipelines (See attached Property Sketch)</u>

To accommodate the construction and installation of the pipelines through your above described property, Trans Mountain requires a Permanent Easement and Temporary Working Space adjacent to the Permanent Easement.

The location of the Permanent Easement and Temporary Working Space is shown on the attached Property Sketch.

2. <u>Details of Compensation Offered</u>

In consideration of granting the aforesaid [check if applicable]:

☐ Permanent Easement to Trans Mountain, Trans Mountain shall offer to pay to the Owner a lump sum of ______________________dollars ($__________________), *plus applicable Goods and Services Tax*, which sum is inclusive of the market value of the portion of the Land which comprises the Permanent Easement as set out in Paragraph 3 hereof. The proposed Permanent Easement Agreement will provide that, as an alternative to the lump sum payment, the Owner has the option of requiring the compensation to be paid by annual or periodic payments of equal or different amounts over a period of time

☐ Temporary Working Space to Trans Mountain, Trans Mountain shall offer to pay to the Owner a lump sum of __________________ dollars($__________________), *plus applicable Goods and Services Tax*, which sum is inclusive of the market value of the portion of the Land which comprises the Temporary Working Space as set out in Paragraph 3 hereof.

3. **Detailed Statement of Value of Lands Required**

After having considered the current use of the Land and neighbouring lands, any probable change in use of the Land and neighbouring lands in light of current zoning laws and economic considerations, recent sales of similar lands in the vicinity of the Land and other relevant factors, Trans Mountain has determined that present market value of the **[check if applicable]**:

☐ Permanent Easement, ignoring any residual value to the Owner, is $ _________________ per hectare ($_________________ per acre) *plus applicable Goods and Services Tax.*

☐ Temporary Working Space, accounting for an approximation of the reversionary value to the Owner, is $ _________________ per hectare ($_________________ per acre), *plus applicable Goods and Services Tax.*

Trans Mountain will require only the limited rights as described in the Permanent Easement Agreement and Temporary Working Space Agreement, and the Owner will continue to be able to use the Permanent Easement area and Temporary Working Space subject to the conditions set out in the Agreements.

4. **Description of Procedure for Approval of Detailed Route of Pipelines**

Sections 34 through 39, inclusive, of the *National Energy Board Act* (the "Act") establish a procedure for approval of the detailed route of a pipeline.

Those sections provide that after a pipeline company has submitted to the National Energy Board (the "Board") a plan showing the proposed route of a pipeline, the company must serve on owners of lands proposed to be acquired and publish notices which describe the proposed detailed route of the pipeline and the location of the offices of the Board. Within thirty (30) days of service or last publication of such notice, an owner or person who anticipates that his/her land may be adversely affected by the proposed detailed route may oppose the detailed route by filing with the Board a written statement setting forth the nature of his/her interest in the land and the grounds for his/her opposition to that detailed route.

Where a written statement opposing the route is filed within the time limited therefore, the Board must, subject to certain exceptions, forthwith order that a public hearing be conducted within the area in which the lands to which the written statement relates are situated with respect to any grounds of opposition set out in such statement. At such hearing each person who properly filed a written statement will be allowed to make representations and the Board may allow any other interested person to make such representations as the Board deems proper. Following a hearing and after consideration of all representations made, the Board may either approve or refuse to approve the plan showing the proposed detailed route of the pipeline as filed by the pipeline company and in granting any approval the Board may impose such terms and conditions as it considers proper. The Board may not give its approval to a plan unless it has taken into account all written statements properly filed with it and all representations made to it at a public hearing in order to determine the best possible route of the pipeline and the most appropriate methods and timing of constructing the pipeline.

If the Owner and Trans Mountain enter into a Permanent Easement Agreement Trans Mountain will discuss with you the specific route of the proposed pipeline right-of-way, as well as the proposed methods and timing of the construction. The Permanent Easement Agreement that you will be asked to sign will contain your acknowledgment that you are in agreement with the location of the right-of-way, the methods and timing of construction and that you will not object if Trans Mountain does not provide you with notice of the detailed route of the pipeline pursuant to s. 34(1) of the Act and further waive your right to request a hearing to settle the detailed pipeline route.

Initial

For the complete text of the provisions relating to the procedure for determination and approval of a pipeline route and the provisions that result in exemption from such procedures, reference should be made to those sections of the Act referenced in this Notice. The description of sections of the Act referenced in this Notice is subject to the express provisions of the Act.

5. Description of Procedure Available for Negotiation and Arbitration of Compensation Payable

Sections 88 through 103, inclusive, of the Act establish a procedure for negotiation and arbitration in the event that an owner of land and a pipeline company are unable to agree on any matter respecting the amount of compensation payable under the Act for the acquisition of lands, or for damages suffered as a result of the operations of the pipeline company or on any issue related to such compensation.

These sections provide, in effect, that if the pipeline company and an owner of lands have not agreed on any such issue either of them may serve notice of negotiation on the other and on the appropriate federal Minister ("Minister") requesting that the matter be negotiated. Following service of such notice, the Minister must appoint a negotiator who must meet with the parties and, without prejudice to any subsequent proceedings, proceed to attempt to negotiate a settlement of the matter. Within sixty days after commencing the negotiation proceedings, the negotiator must report to the Minister the success or failure of the negotiations and submit a copy of his/her report to both parties.

If either an owner of the land or the pipeline company wishes to dispense with the negotiation proceedings or if the negotiation proceedings have not resulted in settlement of any compensation matter, either the pipeline company or the owner may serve notice of arbitration on the other and on the Minister requesting that the matter be determined by arbitration. Forthwith thereafter the Minister must, subject to certain exceptions, refer the matter to an Arbitration Committee consisting of not less than three members appointed by the Minister, none of whom will be a member, officer or employee of the Board. The

Arbitration Committee must then fix a suitable time and place for a hearing in order to determine all compensation matters referred to in the notice and serve notice of the hearing on the parties. Following such hearing, the Arbitration Committee will determine all compensation matters referred to it and in doing so must consider a number of factors set out in section 97 of the Act, where applicable.

For the complete text of the provisions relating to the procedure for negotiation and arbitration of compensation, reference should be made to those sections of the Act referenced in this Notice. The description of sections of the Act referenced in this Notice is subject to the express provisions of the Act.

6. Further Communications

This Notice is not an offer and does not obligate either the Owner or Trans Mountain to enter into an Agreement.

If you have any questions, please contact Trans Mountain, Suite 2700, Stock Exchange Tower 300 – 5th Avenue S.W., Calgary, Alberta, T21 5J2.
The address of the National Energy Board is 444 - Seventh Avenue S.W., Calgary, Alberta, T2P 0X8.

TRANS MOUNTAIN PIPELINE L.P. by the General Partner TRANS MOUNTAIN PIPLINE ULC

Per: ______________________________

____
Print name and position

Per: ______________________________

____
Print name and position

TRANS MOUNTAIN PIPELINE L.P. by the General Partner TRANS MOUNTAIN ULC (“Trans Mountain”)

NOTICE PURSUANT TO SECTION 87(1) OF THE NATIONAL ENERGY BOARD ACT FOR EASEMENT PROVINCE OF ALBERTA

TO: **The Crown in the Right of Alberta**

being the registered owner(s) (the “**Owner**”) of the lands described as follows (the “**Land**”):

(For details on land description, see Schedule “A” attached to and forming part of this Notice)

AND TO: **All crown land disposition holders within the described lands as per Schedule A**

being other persons, as far as can be ascertained, having a potentially relevant interest in the said land.

Trans Mountain hereby gives notice of the following:

1. Description of Lands Required for Pipeline

To accommodate the construction and installation of the proposed facilities, namely a pipeline through your above described property, Trans Mountain requires a Permanent Easement and Temporary Working Space adjacent to the Permanent Easement. The location of the lands required and a description of the required Permanent Easement and Temporary Working Space are shown on the Survey Plans attached as “Schedule B”, which forms part of this Notice.

2. Details of Compensation Offered

In consideration of granting the aforesaid Permanent Easement to Trans Mountain, Trans Mountain shall offer to pay to the Owner a lump sum of ____________________ dollars ($_____________), plus Goods and Services Tax, which sum is calculated in accordance with the provisions of Paragraph 3 hereof.

In consideration of granting the aforesaid Temporary Working Space to Trans Mountain, Trans Mountain shall offer to pay to the Owner a lump sum of ______________________ dollars ($_____________), plus Goods and Services Tax, which sum is calculated in accordance with the provisions of Paragraph 3 hereof.

The proposed Agreement for Easement will provide that, as an alternative to the lump sum payment, the Owner has the option of requiring the compensation to be paid by annual or periodic payment of equal or different amounts over a period of time.

3. Detailed Statement of Value of Lands Required

The value of the portion of the lands which comprises the Permanent Statutory Right of Way is $_________ per hectare, plus Goods and Services Tax.

The value of the portion of the lands which comprises the Temporary Working Space is $______________ per hectare, plus Goods and Services Tax.

4. Description of Procedure for Approval of Detailed Route of Pipeline

Sections 34 through 39, inclusive, of the *National Energy Board Act* (the "Act"), unless waived under section 58 of the act, establish a procedure for approval of the detailed route of a pipeline.

Those sections provide that after a pipeline company has submitted to the National Energy Board (the "Board") a plan showing the proposed route of a pipeline, the company must serve on landowners of lands proposed to be acquired and publish notices which describe the proposed detailed route of the pipeline and the location of the offices of the Board. Within thirty (30) days of service or publication, an owner or person who anticipates that his/her land may be adversely affected by the proposed detailed route may oppose the detailed route by filing with the Board a written statement setting forth the nature of his/her interest in the land and the grounds for his/her opposition.

Where a written statement opposing the route is filed, the Board must, subject to certain exceptions, forthwith order that a public hearing be conducted with respect to such written opposition.

Following a hearing and after consideration of all representations made, the Board may either approve or refuse to approve the plan showing the proposed detailed route of the pipeline as filed by the pipeline company.

5. Description of Procedure Available for Negotiation and Arbitration of Compensation Payable

Sections 88 through 103, inclusive, of the Act establish a procedure for negotiation and arbitration in the event that an owner of land and a pipeline company are unable to agree on any matter respecting the amount of compensation payable under the Act for the acquisition of land, or on damages suffered as a result of the operations of the pipeline company or on any issue related to such compensation.

These sections of the Act provide that either party may serve notice of negotiation on the other and on the appropriate federal Minister ("Minister") requesting that the matter be negotiated. The Minister must then appoint a negotiator who must meet with the parties and proceed to attempt to negotiate a settlement of the matter.

If either the owner of the land or Trans Mountain wishes to dispense with the negotiation proceedings or if the negotiation proceedings have not resulted in settlement of any compensation matter, either the pipeline company or the owner may serve notice of arbitration on the other and on the Minister who must, subject to certain exceptions, refer the matter to an Arbitration Committee consisting of not less than three members appointed by the Minister. Following a hearing, the Arbitration Committee will determine all compensation matters referred to it.

6. Further Communications

This Notice is not an offer and does not obligate either the Owner or Trans Mountain to enter into an Agreement.

If you have any questions, please contact Trans Mountain, Suite 2700, Stock Exchange Tower 300 – 5th Avenue S.W., Calgary, Alberta, T21 5J2. The address of the National Energy Board is 311 - 6 Ave SW, Calgary AB T2P 3H2.

TRANS MOUNTAIN PIPELINE L.P. by the General Partner TRANS MOUNTAIN PIPLINE ULC

Per: ____________________________________

____
Print name and position

Per: ____________________________________

____
Print name and position

NOTICE PURSUANT TO SECTION 87(1) OF THE
NATIONAL ENERGY BOARD ACT FOR EASEMENT

TRANS MOUNTAIN PIPLINE ULC
by the General Partner TRANS MOUNTAIN PIPELINE L.P.
SUITE 2700, STOCK EXCHANGE TOWER, 300 – 5TH AVENUE SW,
CALGARY, ALBERTA T21 5J2.

TRACT:

TRANS MOUNTAIN PIPELINE L.P. by the General Partner TRANS MOUNTAIN ULC
("Trans Mountain")
NOTICE PURSUANT TO SECTION 87(1) OF THE
NATIONAL ENERGY BOARD ACT
PROVINCE OF BRITISH COLUMBIA

TO: ●

being the registered owner(s) (the "**Owner**") of the lands described as follows (the "**Land**"):

(For details on land description, see Schedule "A" attached to and forming part of this Notice)

AND TO: ●

being other persons, as far as can be ascertained, interested in the said Land

Trans Mountain hereby gives notice of the following:

1. <u>Description of Lands Required for Pipeline</u> (See attached Property Sketch)

To accommodate the construction and installation of a pipeline through your above described property, Trans Mountain requires a Statutory Right of Way over part of the Land (the "**SRW Area**") and the right to use Temporary Working Space on part of the Land adjacent to the SRW Area.

The location of the SRW Area and Temporary Working Space is shown on the attached Property Sketch.

2. <u>Details of Compensation Offered</u>

In consideration of granting the aforesaid [check if applicable]:

☐ Statutory Right of Way to Trans Mountain, Trans Mountain shall offer to pay to the Owner a lump sum of ______________________dollars ($__________________), *plus applicable taxes*, which sum is inclusive of the market value of the portion of the Land which comprises the Statutory Right of Way as set out in Paragraph 3 hereof. The proposed Statutory Right of Way Agreement will provide that, as an alternative to the lump sum payment, the Owner has the option of requiring the compensation to be paid by annual or periodic payments of equal or different amounts over a period of time

☐ right to use the Temporary Working Space to Trans Mountain, Trans Mountain shall offer to pay to the Owner a lump sum of __________________ dollars($__________________), *plus applicable taxes*, which sum is inclusive of the market value of the portion of the Land which comprises the Temporary Working Space, accounting for an approximation of the reversionary value to the Owner, as set out in Paragraph 3 hereof.

3. **Detailed Statement of Value of Lands Required**

After having considered the current use of the Land and neighbouring lands, any probable change in use of the Land and neighbouring lands in light of current zoning laws and economic considerations, recent sales of similar lands in the vicinity of the Land and other relevant factors, Trans Mountain has determined that present market value of the **[check if applicable]**:

☐ SRW Area, ignoring any residual value to the Owner, is $ __________________per hectare ($__________________per acre) plus applicable taxes.

☐ Temporary Working Space, accounting for an approximation of the reversionary value to the Owner, is $ __________________per hectare ($__________________per acre), *plus applicable taxes*.

Trans Mountain will require only the limited rights as described in the Statutory Right of Way Agreement and Temporary Working Space Agreement, and the Owner will continue to be able to use the SRW Area and Temporary Working Space subject to the conditions set out in such acquisition agreements.

4. **Description of Procedure for Approval of Detailed Route of Pipelines**

Sections 34 through 39, inclusive, of the National Energy Board Act (the "Act") establish a procedure for approval of the detailed route of a pipeline.

Those sections provide that after a pipeline company has submitted to the National Energy Board (the "Board") a plan showing the proposed route of a pipeline, the company must serve on owners of lands proposed to be acquired and publish notices which describe the proposed detailed route of the pipeline and the location of the offices of the Board. Within thirty (30) days of service or last publication of such notice, an owner or person who anticipates that his/her land may be adversely affected by the proposed detailed route may oppose the detailed route by filing with the Board a written statement setting forth the nature of his/her interest in the land and the grounds for his/her opposition to that detailed route.

Where a written statement opposing the route is filed within the time limited therefore, the Board must, subject to certain exceptions, forthwith order that a public hearing be conducted within the area in which the lands to which the written statement relates are situated with respect to any grounds of opposition set out in such statement. At such hearing each person who properly filed a written statement will be allowed to make representations and the Board may allow any other interested person to make such representations as the Board deems proper. Following a hearing and after consideration of all representations made, the Board may either approve or refuse to approve the plan showing the proposed detailed route of the pipeline as filed by the pipeline company and in granting any approval the Board may impose such terms and conditions as it considers proper. The Board may not give its approval to a plan unless it has taken into account all written statements properly filed with it and all representations made to it at a public hearing in order to determine the best possible route of the pipeline and the most appropriate methods and timing of constructing the pipeline.

If the Owner and Trans Mountain enter into a Statutory Right of Way Agreement Trans Mountain will discuss with you the specific route of the proposed pipeline right-of-way, as well as the proposed methods and timing of the construction. The Permanent Easement Agreement that you will be asked to sign will contain your acknowledgment that you are in agreement with the location of the right-of-way, the methods and timing of construction and that you will not object if Trans Mountain does not provide you with notice of the detailed route of the pipeline pursuant to s. 34(1) of the Act and further waive your right to request a hearing to settle the detailed pipeline route.

Initial

For the complete text of the provisions relating to the procedure for determination and approval of a pipeline route and the provisions that result in exemption from such procedures, reference should be made to those sections of the Act referenced in this Notice. The description of sections of the Act referenced in this Notice is subject to the express provisions of the Act.

5. Description of Procedure Available for Negotiation and Arbitration of Compensation Payable

Sections 88 through 103, inclusive, of the Act establish a procedure for negotiation and arbitration in the event that an owner of land and a pipeline company are unable to agree on any matter respecting the amount of compensation payable under the Act for the acquisition of lands, or for damages suffered as a result of the operations of the pipeline company or on any issue related to such compensation.

These sections provide, in effect, that if the pipeline company and an owner of lands have not agreed on any such issue either of them may serve notice of negotiation on the other and on the appropriate federal Minister (“Minister”) requesting that the matter be negotiated. Following service of such notice, the Minister must appoint a negotiator who must meet with the parties and, without prejudice to any subsequent proceedings, proceed to attempt to negotiate a settlement of the matter. Within sixty days after commencing the negotiation proceedings, the negotiator must report to the Minister the success or failure of the negotiations and submit a copy of his/her report to both parties.

If either an owner of the land or the pipeline company wishes to dispense with the negotiation proceedings or if the negotiation proceedings have not resulted in settlement of any compensation matter, either the pipeline company or the owner may serve notice of arbitration on the other and on the Minister requesting that the matter be determined by arbitration. Forthwith thereafter the Minister must, subject to certain exceptions, refer the matter to an Arbitration Committee consisting of not less than three members appointed by the Minister, none of whom will be a member, officer or employee of the Board. The Arbitration Committee must then fix a suitable time and place for a hearing in order to determine all compensation matters referred to in the notice and serve notice of the hearing on the parties. Following such hearing, the Arbitration Committee will determine all compensation matters referred to it and in doing so must consider a number of factors set out in section 97 of the Act, where applicable.

For the complete text of the provisions relating to the procedure for negotiation and arbitration of compensation, reference should be made to those sections of the Act referenced in this Notice. The description of sections of the Act referenced in this Notice is subject to the express provisions of the Act.

6. <u>Further Communications</u>

This Notice is not an offer and does not obligate either the Owner or Trans Mountain to enter into an Agreement.

If you have any questions, please contact Trans Mountain, Suite 2700, Stock Exchange Tower 300 – 5th Avenue S.W., Calgary, Alberta, T21 5J2..

The address of the National Energy Board is 444 - Seventh Avenue S.W., Calgary, Alberta, T2P 0X8.

TRANS MOUNTAIN PIPELINE L.P. by its General Partner TRANS MOUNTAIN PIPELINE ULC

Per: ______________________________

____
Print name and position

Per: ______________________________

____
Print name and position

TRANS MOUNTAIN PIPELINE L.P.
("Trans Mountain")
NOTICE PURSUANT TO SECTION 87(1) OF THE
NATIONAL ENERGY BOARD ACT
PROVINCE OF BRITISH COLUMBIA

TO: **The Crown in the Right of British Columbia**

being the owner (the "**Owner**") of the lands described as follows (the "**Land**"):

(For details on land description, see Schedule "A" attached to and forming part of this Notice)

AND TO: **All crown land tenure holders within the described lands as per Schedule A**

being other persons, as far as can be ascertained, having a potentially relevant interest in the said land.

Trans Mountain hereby gives notice of the following:

1. **Description of Lands Required for Pipeline**

To accommodate the construction and installation of the proposed facilities, namely a pipeline through your above described property, Trans Mountain requires an easement without dominant tenement ("Right of Way") over part of the Land (the "RW Area") and the right to use the Temporary Working Space on part of the Land adjacent to the RW Area.. The location of the lands required and a description of the required RWArea and Temporary Working Space are shown on the Property Sketch attached as "Schedule B", which forms part of this Notice.

2. **Details of Compensation Offered**

In consideration of granting the aforesaid Right of Way to Trans Mountain, Trans Mountain shall offer to pay to the Owner a lump sum of _____________ dollars ($________), plus Goods and Services Tax, which sum is calculated in accordance with the provisions of Paragraph 3 hereof.

The proposed Right of Way Agreement will provide that, as an alternative to the lump sum payment, the Owner has the option of requiring the compensation to be paid by annual or periodic payment of equal or different amounts over a period of time.

In consideration of granting the aforesaid right to use the Temporary Working Space to Trans Mountain, Trans Mountain shall offer to pay to the Owner a lump sum of ______________ dollars ($________), plus Goods and Services Tax, which sum is calculated in accordance with the provisions of Paragraph 3 hereof.

3. **Detailed Statement of Value of Lands Required**

The value of the portion of the Land which comprises the RW Area is $___________ per hectare, plus Goods and Services Tax, according to the rates and fees prescribed by the Owner.

The value of the portion of the Land which comprises the Temporary Working Space is $___________ per hectare, plus Goods and Services Tax, according to the rates and fees prescribed by the Owner..

4. Description of Procedure for Approval of Detailed Route of Pipeline

Sections 34 through 39, inclusive, of the National Energy Board Act (the "Act"), unless waived under section 58 of the act, establish a procedure for approval of the detailed route of a pipeline.

Those sections provide that after a pipeline company has submitted to the National Energy Board (the "Board") a plan showing the proposed route of a pipeline, the company must serve on landowners of lands proposed to be acquired and publish notices which describe the proposed detailed route of the pipeline and the location of the offices of the Board. Within thirty (30) days of service or publication, an owner or person who anticipates that his/her land may be adversely affected by the proposed detailed route may oppose the detailed route by filing with the Board a written statement setting forth the nature of his/her interest in the land and the grounds for his/her opposition.

Where a written statement opposing the route is filed, the Board must, subject to certain exceptions, forthwith order that a public hearing be conducted with respect to such written opposition.

Following a hearing and after consideration of all representations made, the Board may either approve or refuse to approve the plan showing the proposed detailed route of the pipeline as filed by the pipeline company.

5. Description of Procedure Available for Negotiation and Arbitration of Compensation Payable

Sections 88 through 103, inclusive, of the Act establish a procedure for negotiation and arbitration in the event that an owner of land and a pipeline company are unable to agree on any matter respecting the amount of compensation payable under the Act for the acquisition of land, or on damages suffered as a result of the operations of the pipeline company or on any issue related to such compensation.

These sections of the Act provide that either party may serve notice of negotiation on the other and on the appropriate federal Minister ("Minister") requesting that the matter be negotiated. The Minister must then appoint a negotiator who must meet with the parties and proceed to attempt to negotiate a settlement of the matter.

If either the owner of the land or Trans Mountain wishes to dispense with the negotiation proceedings or if the negotiation proceedings have not resulted in settlement of any compensation matter, either the pipeline company or the owner may serve notice of arbitration on the other and on the Minister who must, subject to certain exceptions, refer the matter to an Arbitration Committee consisting of not less than three members appointed by the Minister. Following a hearing, the Arbitration Committee will determine all compensation matters referred to it.

6. <u>Further Communications</u>

This Notice is not an offer and does not obligate either the Owner or Trans Mountain to enter into an Agreement.

If you have any questions, please contact Trans Mountain, Suite 2700, Stock Exchange Tower 300 – 5th Avenue S.W., Calgary, Alberta, T21 5J2.

The address of the National Energy Board is 311 - 6 Ave SW, Calgary AB T2P 3H2.

TRANS MOUNTAIN PIPELINE L.P. by the General Partner TRANS MOUNTAIN PIPELINE ULC

Per: ______________________________

____
Print name and position

Per: ______________________________

____
Print name and position

NOTICE PURSUANT TO SECTION 87(1) OF THE
NATIONAL ENERGY BOARD ACT FOR EASEMENT

TRANS MOUNTAIN PIPELINE L.P.
by the General Partner TRANS MOUNTAIN PIPELINE ULC
SUITE 2700, STOCK EXCHANGE TOWER, 300 – 5TH AVENUE SW,
CALGARY, ALBERTA T21 5J2.

Appendix E Agreement for Easement, Province of Alberta

TRACT:

TRANS MOUNTAIN PIPELINE L.P. by the General Partner TRANS MOUNTAIN ULC
("Trans Mountain")
AGREEMENT FOR EASEMENT
PROVINCE OF ALBERTA

I, (We) <>

(the "**Owner**"), being registered as owner or entitled to become registered as owner of an estate in fee simple, subject however to such encumbrances, liens and interests as appear on the Certificate of Title, in all that certain tract of land situated in the Province of Alberta being composed of:

as described in the Certificate of Title numbered ________________________ registered with the Land Titles Office for the North Alberta Land Registration District (the "**Lands**"),

and in consideration of the sum of ________________________ Dollars ($_______________), the receipt of which is hereby acknowledged, now paid or payable to the Owner (or to others having an interest in the Lands by encumbrance or otherwise), by Trans Mountain, a corporation incorporated under the laws of Canada, and having its operating office in the City of Calgary, in the Province of Alberta, and in consideration of the covenants and conditions hereinafter mentioned,

DO HEREBY GRANT, CONVEY, SET OVER AND TRANSFER to Trans Mountain, for itself, its employees, agents, contractors, subcontractors, successors and assigns, an easement and right of way (also referred to as the "**right-of-way**"), across, over, under, in, through or on the Lands to survey, construct, operate, maintain, inspect, patrol (including aerial patrol), alter, remove, replace, reconstruct and repair two or more pipelines (subject to Clause 21 herein) and other facilities appurtenant, affixed or incidental thereto, including, but without limiting the generality of the foregoing, all such pipes, drips, valves, fittings, connections, meters, cathodic protection, equipment and other equipment and appurtenances, whether or not similar to the foregoing as may be useful or convenient in connection therewith or incidental thereto (hereinafter collectively referred to as the "**Pipeline**"), for the transportation, storage and handling of oil, other liquid and gaseous hydrocarbons and products thereof, together with the right of ingress and egress over the remainder of the Lands, to and from the right-of-way for Trans Mountain, its personnel, equipment, contractors and agents for all purposes necessary or incidental to the exercise and enjoyment of the rights herein granted.

The rights and easement are granted as and from the date hereof and for so long hereafter as Trans Mountain desires to exercise same on the following terms and conditions which are hereby mutually agreed to:

1. Trans Mountain shall, upon the completion of a legal survey plan, deposit for registration at the appropriate Land Titles Office a plan of survey limiting the right-of-way across, over, under, in, through or on the Lands to a strip of land being generally ________________________ in width within the Lands which right-of-way shall be substantially in the location as shown on the property sketch attached hereto. Trans Mountain shall file a plan of survey within a reasonable period of time having regard to

all circumstances. Following registration of such plan of survey Trans Mountain shall, if it has not already done so, forward to the Owner at the address set forth in Clause 20 hereof an extract from the plan of survey showing the precise location of the right-of-way across, over, under, in, through or on the Lands (the "**Surveyed Right-of-Way**"). Upon registration of the plan of survey, reference to "right-of-way" in this Agreement shall mean the Surveyed Right-of-Way.

2. Trans Mountain, having delivered or mailed to the Owner the extract from the plan of survey, shall as soon as it is practicable to do so, cause to be registered in the appropriate Land Titles Office, a document restricting the right-of- way to the Surveyed Right of Way. Notwithstanding the registration of such document Trans Mountain shall continue to be entitled to enjoy the right of ingress and egress to and from the Surveyed Right-of-Way across the remainder of the Lands as set out in the granting provision of this Agreement.

3. Trans Mountain shall pay the compensation to the Owner for the grant of easement and right of way as follows: Delete (a) or (b):

   (a) one lump sum payment of ________________________________ Dollars ($____________________),plus Good and Services Tax
   (initial)

   - or -

   (b) by annual or periodic payments of equal or different amounts over a period of time as set forth in Schedule One attached hereto and forming part hereof; (initial)

   If the Lump Sum Payment option is chosen (option 3(a)), such payment shall be made on or before construction is commenced on the right-of-way. If option 3(b) is chosen the first of such payments shall commence on or before construction is commenced on the right-of-way. In the event that a lump sum payment or the first annual or periodic payment, as the case may be, has not been made before ____________________, 20____, then this Agreement shall terminate and be at an end for all purposes and Trans Mountain shall forthwith execute and register such documents as may be necessary to discharge this Agreement from the Certificate of Title for the Lands and shall notify the Owner of the registration of the discharge.

4. The Owner shall have the right fully to use and enjoy the right-of-way except as may be necessary for the purposes herein granted to Trans Mountain provided however that the Owner shall not, without the prior written consent of Trans Mountain, which consent shall not be unreasonably withheld, excavate, drill, install, erect, place, plant or permit to be excavated, drilled, installed, erected, placed, or planted on, over, under, across or through the right-of-way any pit, well, foundation, pavement, building, tree, or any other structure, installation, object or improvement.

5. Notwithstanding the provisions of Clause 4, Trans Mountain will not object to the Owner:

(i) paving existing farm lanes, private roads, driveways, and sidewalks across the right-of-way;

(ii) erecting fences across the right-of-way or any portion thereof; or

(iii) constructing drains or repairing drains on the right-of-way or any portion thereof;

provided, however, that the Owner agrees to exercise a high degree of care in carrying out any excavation or drilling necessary for such fencing, paving or drainage, and in no event shall the Owner or his contractors perform such work in such a manner as to endanger or damage the Pipeline. Before the commencement of any such work, the Owner shall give to Trans Mountain at least five (5) days prior notice in writing so as to enable a representative of Trans Mountain to inspect the site of the proposed work and to advise how the work may be performed without damage to the Pipeline.

6. Trans Mountain will compensate the Owner for all damages suffered as a result of Trans Mountain's operations.

7. Trans Mountain will, as soon as weather and soil conditions permit and insofar as it is practicable so to do, bury and maintain the Pipeline in a manner that will not interfere with the drainage or ordinary cultivation of the Lands, and will restore all drains damaged or disturbed by the operation, according to good drainage practice.

8. Notwithstanding that in constructing, maintaining and operating its Pipeline Trans Mountain may install pipe and other equipment and appurtenances in, on, over, under, across or through the right-of-way in such a manner that it or they become affixed to the Lands, the title to such pipe and other equipment and appurtenances shall until surrendered, remain in Trans Mountain. Trans Mountain may at any time remove the whole or any part of the Pipeline.

9. Upon the discontinuance of the use of the said right-of-way and of the exercise of the rights hereby granted, Trans Mountain shall and will restore the right-of-way to the same condition, so far as it is practicable so to do, as the same were in prior to the entry thereon and the use thereof by Trans Mountain. Trans Mountain agrees to withdraw and discharge any registrations at the Land Titles Office pertaining to this Agreement upon the abandonment of the right-of- way.

10. Trans Mountain in performing and observing the covenants and conditions contained in this Agreement, shall peaceably hold and enjoy the rights and easement hereby granted without hindrance, molestation or interruption on the part of the Owner or of any person, firm or corporation claiming by, through, under or in trust for the Owner.

11. Either party shall have the absolute right to assign this Agreement in whole or in part, and upon such assignment, shall give to the other party written notice thereof within ten (10) days, but Trans Mountain need not give such notice upon assignment in the course of its corporate financing by way of a deed of trust, mortgage, debenture or a floating charge or upon assignment arising out of an amalgamation or merger.

12. This Agreement shall not affect or prejudice Trans Mountain's statutory rights to acquire an easement or any portion of the Lands under the provisions of the *National Energy Board Act* (the "**Act**"), or any other laws, which rights may be exercised at Trans Mountain's discretion in the event of the Owner being unable or unwilling for any reason to perform this Agreement or to give to Trans Mountain a clear and unencumbered title to the right-of-way and easement herein granted.

13. The Owner will, if so requested by Trans Mountain, execute such further documents of title and assurances in respect of the Lands as may be required to perfect Trans Mountain's interest in the Lands.

14. Nothing contained herein shall vest in Trans Mountain any title to mines or minerals in or under the right-of-way, except only the parts thereof that are necessary to be excavated, carried away or used in the construction of the Pipeline belonging to Trans Mountain.

15. Where Trans Mountain requires an above ground installation of the Pipeline upon the right-of-way (other than pipeline markers installed at property or fence lines) or requires any part of the right-of-way to be fenced, the Owner shall be entitled to additional compensation to be agreed upon between the parties, or failing agreement, pursuant to the procedure available for negotiation and arbitration under Part V of the Act.

16. Trans Mountain will not object to any application made by the Owner under Section 112 of the Act so long as the proposed crossing is made in accordance with good engineering practice and does not interfere with the operation of the Pipeline.

17. This Agreement is a covenant running with the Lands and the provisions of this Agreement shall extend to, be binding upon, and enure to the benefit of the heirs, executors, administrators, successors and assigns of the Owner and Trans Mountain, respectively.

18. Wherever the singular or masculine is used in this Agreement, it shall be construed as if the plural or feminine or the neuter, as the case may be, had been used where the context so requires.

19. It is agreed that the Owner shall have the right to transfer or convey his interest in the Lands and the covenants and conditions herein contained in one or more parcels and by one or more conveyances and that all the covenants and conditions herein contained shall extend to and be binding upon and enure to the benefit of each and all of the heirs, executors, administrators, successors, and assigns of the Owner in respect of each and every parcel transferred or conveyed.

20. All notices to be given hereunder may be given by registered letter addressed to Trans Mountain, Suite 2700, Stock Exchange Tower 300 – 5th Avenue S.W., Calgary, Alberta, T21 5J2, , and to the Owner at ________________________________ or such other address as Trans Mountain and the Owner may respectively appoint, from time to time, in writing, and any such notice shall be deemed to be given to and received seven (7) days after the mailing thereof, postage prepaid.

21. Trans Mountain proposes to install two (2) pipelines in the right-of-way. Trans Mountain will only install an additional pipeline or pipelines in the right-of-way with the consent and agreement of the Owner, or, in the absence of such consent and agreement, in accordance with all authorizations and determinations, including with respect to any additional compensation payable, made under the Act.

22. The Owner agrees that Trans Mountain may, at its option, at any time in the course of operating the Pipeline enter upon the right-of-way with men and equipment and remove all shrubs and trees from the right-of-way.

23. Trans Mountain shall indemnify the Owner from all liabilities, damages, claims, suits and actions arising out of the operations of Trans Mountain on the Lands other than liabilities, damages, claims, suits and actions resulting from the negligence or willful misconduct of the Owner. Notwithstanding the foregoing, Trans Mountain shall not in any event be liable of any indirect or consequential damages.

24. The Owner confirms having the option of requiring the compensation for the rights herein granted to be made by one lump sum payment or by annual or periodic payments of equal or different amounts over a period of time and that the Owner has selected the method of compensation hereinbefore set out. The Owner further confirms that if the Owner has selected annual or other periodic payments, the amount of such compensation payable by Trans Mountain shall be reviewed every five (5) years if the period of compensation extends beyond five (5) years.

25. The Owner consents to the collection and use of his/her personal information within this form. Trans Mountain collects this type of personal information for the purposes of general land rights acquisition and regulatory disclosure. The Owner consents to the collection, use and disclosure of its personal information for these legitimate business purposes in relation to land matters of Trans Mountain.

26. The Owner acknowledges receipt of a notice given pursuant to Section 87(1) of the Act and given prior to the entering into of this Agreement, setting out or accompanied by:

    (a) a description of the Lands of the Owner required by Trans Mountain for a section or part of the Pipelines;

    (b) details of the compensation offered by Trans Mountain for such Lands required;

    (c) a detailed statement made by Trans Mountain of the value of such Lands required in respect of which compensation was offered;

    (d) a description of the procedure for approval of the detailed route of Trans Mountain's Pipelines; and

    (e) a description of the procedure available for negotiation and arbitration under Part V of the Act in the event that the Owner and Trans Mountain are unable to agree on any matter respecting the compensation payable.

27. The Owner acknowledges that Trans Mountain has explained the specific route of the proposed pipeline right of way, as well as the proposed methods and timing of the construction of the Pipeline that will be installed therein. This Agreement confirms that the Owner is in agreement with the location of the pipeline right of way, and the methods and timing of construction of the Pipeline that will be installed therein. The Owner hereby waives any right to ask for a hearing to settle the detailed Pipeline route or the methods and timing of construction, and understands that Trans Mountain may not serve the Owner with further Notice of the detailed route of the Pipeline pursuant to s. 34 (1)(a) of the Act.

IN WITNESS WHEREOF the parties hereto have executed and delivered this Agreement as of the _______ day of _____________________________, 20____.

SIGNED in the presence of:

Witness:	Owner:
Witness:	Owner:

TRANS MOUNTAIN PIPELINE L.P.by the General Partner TRANS MOUNTAIN PIPLINE ULC

Per: ______________________________

____
Print name and position

Per: ______________________________

____
Print name and position

CONSENT OF SPOUSE

I, ______________________________________ being married to the within named do hereby give my consent to the disposition of our homestead, made in this instrument, and I have executed this document for the purpose of giving up my life estate and other dower rights in the said property given to me by the *Dower Act*, to the extent necessary to give effect to the said disposition.

CERTIFICATE OF ACKNOWLEDGEMENT BY SPOUSE

1. This document was acknowledged before me by _______________________________, apart from her husband (his wife).

2. ____, acknowledged to me that she (he):

   (a) is aware of the nature of the disposition or agreement;

   (b) is aware that the *Dower Act*, gives her (him) a life estate in the homestead and the right to prevent disposition of the homestead by withholding consent;

   (c) consents to the disposition or agreement for the purpose of giving up the life estate and other dower rights in the homestead given to her (him) by the *Dower Act*, to the extent necessary to give effect to the said disposition or agreement;

   (d) is executing the document freely and voluntarily without any compulsion on the part of her husband (his wife).

DATED at the _________ of __________________________, in the Province of Alberta, this _________ day of _______________________________, 20_____.

____
A Commissioner for Oaths in and for the Province of Alberta

DOWER AFFIDAVIT

CANADA	)	I, _____________________________ of the
PROVINCE OF ALBERTA	)	_________________ of _______________
TO WIT:	)	in the Province of Alberta

MAKE OATH AND SAY:

1. THAT I am the Grantor named in the within Instrument.

2. THAT I am not married.

- OR -

3. THAT neither myself nor my spouse have resided on the within mentioned Land at any time since our marriage.

SWORN before me at the _______________ of ______________________________ in the Province of Alberta, this ___ day of ________________, A.D. 20___	))))))	____
____ A Commissioner for Oaths in and for the Province of Alberta	)))	

AFFIDAVIT OF EXECUTION

CANADA	)	I, ____________________________ of the
PROVINCE OF ALBERTA	)	_________________ of ________________
TO WIT:	)	in the Province of Alberta

MAKE OATH AND SAY:

1. THAT I was personally present and did see _________________________ named in the within Instrument who is (are) personally known to me to be the person(s) named therein, duly sign and execute the same for the purpose named therein.

2. THAT the same was executed at the _________________________of _______________, in the Province of Alberta, and that I am the subscribing witness thereto.

3. THAT I know the said ____ named and he (she) (each) is in my belief, of the full age of eighteen years.

SWORN before me at the _______________ of ______________________________ in the Province of Alberta, this ___ day of ________________, A.D. 20___	)	____
____	)	
A Commissioner for Oaths in and for the Province of Alberta	)	

CONSENT BY OCCUPANT(S)/PURCHASER(S) OR OTHER INTERESTED PARTIES

I (We), __________________________of ___________________ in the Province of Alberta having an interest in the within Lands by virtue of an Agreement or Instrument dated the ____day of _____________________; **DO HEREBY AGREE**, that all my (our) rights, interests and estate which are, or may be, affected by the Agreement for Easement shall be fully bound by the terms and conditions thereof both now and henceforth.

DATED at the ______________ of _____________________, in the Province of Alberta, this _________ day of ____________________________, 20____.

____	____
Witness:	Owner:
____	____
Witness:	Owner:

AFFIDAVIT OF EXECUTION

CANADA	)	I, ____________________________ of the
PROVINCE OF ALBERTA	)	__________________ of ________________
TO WIT:	)	in the Province of Alberta,

MAKE OATH AND SAY:

1. THAT I was personally present and did see ______________________ named in the within Instrument who is (are) personally known to me to be the person(s) named therein, duly sign and execute the same for the purpose named therein.

2. THAT the same was executed at the ___________________ of ________________, in the Province of Alberta, and that I am the subscribing witness thereto.

3. THAT I know the said ______________________________________ named and he (she) (each) is in my belief, of the full age of eighteen years.

SWORN before me at the _______________ of ______________________________ in the Province of Alberta, this ___ day of ________________, A.D. 20___	)	
	)	_______________________________________
_______________________________________	)	
A Commissioner for Oaths in and for the Province of Alberta	)	

ATTACHED TO AND FORMING
PART OF THE AGREEMENT
FOR EASEMENT

SCHEDULE ONE
Annual or Periodic Payment

The consideration for this Agreement is the sum of ___________________________ Dollars ($______________) of lawful money of Canada to be paid on or before construction is commenced upon the Lands, the receipt of which is hereby acknowledged by the Owner, and thereafter the sum of ______________________ Dollars ($_____________) of lawful money of Canada to be paid on or before the anniversary date thereafter for a period of _________________ (________________) years. The amount of any annual or periodic payment will be reviewed every five (5) years.

The Owner hereby agrees to and accepts the annual or periodic payment set out above.

Witness:	Owner:
Witness:	Owner:
Witness:	Owner:

FORM 31.1

LAND TITLES ACT
(Section 161)

AFFIDAVIT VERIFYING CORPORATE SIGNING AUTHORITY

I, ______________________ of ______________________________ in the province of Alberta, make oath and say:

1. I am an officer or a director of Trans Mountain named in the within or annexed instrument (or caveat).

2. I am authorized by the corporation to execute the instrument (or caveat) without affixing a corporate seal.

SWORN before me at the _______________ of ______________________________ in the Province of Alberta, this ___ day of ________________, A.D. 20___	)	____
____ A Commissioner for Oaths in and for the Province of Alberta	)	

Appendix F *Land Title Act* Form C and Statutory Right of Way Agreement, Province of British Columbia

Tract:_________

LAND TITLE ACT
FORM C
(Section 233)

Province of British Columbia

GENERAL INSTRUMENT - PART 1 (This area for Land Title Office Use)

1. APPLICATION: (Name, address, phone number and signature of applicant, applicant's solicitor or agent)
<@>

Per:

2. PARCEL IDENTIFIER(S) AND LEGAL DESCRIPTION(S) OF LAND:*

(PID) (LEGAL DESCRIPTION)

____

3. NATURE OF INTEREST:*

DESCRIPTION	DOCUMENT REFERENCE (page and paragraph)	PERSON ENTITLED TO INTEREST
Statutory Right of Way	**Entire Document**	**Transferee**

4. TERMS: Part 2 of this instrument consists of (select one only):

(a)	Filed Standard Charge Terms		D.F. Number:
(b)	Express Charge Terms	X	Annexed as Part 2
(c)	Release		There is no Part 2 of this instrument

A selection of (a) includes any additional or modified terms referred to in Item 7 or in a schedule annexed to this instrument. If (c) is selected, the charge described in Item 3 is released or discharged as a charge on the land described in Item 2.

5. TRANSFEROR(S):*

6. TRANSFEREE(S): (including postal address(es) and postal code(s))*

TRANS MOUNTAIN PIPELINE ULC (Extra-Provincial Registration No. A0070893)
Suite 2700, 300 – 5th Avenue SW, Calgary, Alberta T2P 5J2

7. ADDITIONAL OR MODIFIED TERMS:* n/a

8. EXECUTION(S): This instrument creates, assigns, modifies, enlarges, discharges, or governs the priority of the interest(s) described in Item 3 and the Grantor(s) and every other signatory agree to be bound by this instrument, and acknowledge(s) receipt of a true copy of the filed standard charge terms, if any.

Officer Signature(s)	EXECUTION DATE Y	M	D	Party(ies) Signature(s)
				TRANS MOUNTAIN PIPELINE ULC by its authorized signatory(ies):
Name:				
				by its authorized signatory(ies):
Name:				[TRANSFEROR]

OFFICER CERTIFICATION:

Your signature constitutes a representation that you are a solicitor, notary public or other person authorized by the Evidence Act, R.S.B.C. 1996, c. 124, to take affidavits for use in British Columbia and certifies the matters set out in Part 5 of the Land Title Act as they pertain to the execution of this instrument.

* If space insufficient, enter "SEE SCHEDULE" and attach schedule in Form E.

Terms of Instrument – Part 2

TRACT: __________

TRANS MOUNTAIN PIPELINE ULC
STATUTORY RIGHT OF WAY AGREEMENT
PROVINCE OF BRITISH COLUMBIA

WHEREAS ____________________ (the "**Owner**") is the registered owner of an estate in fee simple, subject however to such encumbrances, liens and interests as appear on the Indefeasible Title, in all that certain tract of land described in Item 2 of Part 1 of this General Instrument (the "**Lands**");

AND WHEREAS Trans Mountain Pipeline ULC ("**Trans Mountain**") has requested the Owner to grant the statutory right of way contained herein (the "**Statutory Right of Way**") across, over, under, in, through or on that part of the Lands included in Statutory Right of Way Plan <@> (the "SRW Area") on the terms and conditions set out herein;

AND WHEREAS the Statutory Right of Way herein granted is necessary for the operation and maintenance of Trans Mountain's undertaking;

AND WHEREAS Trans Mountain has been designated under Section 218(1)(d) of the *Land Title Act* to be the grantee of the Statutory Right of Way and such designation has been deposited in the <@> Land Title Office under <@>.

NOW THEREFORE THIS INSTRUMENT WITNESSES that in consideration of the sum of ____________________ Dollars ($__________), the receipt of which is hereby acknowledged, now paid or payable to the Owner, by Trans Mountain, and in consideration of the covenants and conditions on the part Trans Mountain hereinafter mentioned the Owner does:

HEREBY GRANT, CONVEY, SET OVER AND TRANSFER to Trans Mountain, for itself, its employees, agents, contractors, subcontractors, successors and assigns, a statutory right of way under Section 218 of the *Land Title Act* across, over, under, in, through or on the SRW Area to survey, construct, operate, maintain, inspect, patrol (including aerial patrol), alter, remove, replace, reconstruct and repair one or more pipelines (subject to Clause 19 herein) and other facilities appurtenant, affixed or incidental thereto, including, but without limiting the generality of the foregoing, all pipes, drips, valves, fittings, connections, meters, cathodic protection equipment, and other equipment and appurtenances whether or not similar to the foregoing (hereinafter collectively referred to as the "**Pipeline**"), for the transportation, storage and handling of oil, other liquid and gaseous hydrocarbons, and products thereof, together with the right of ingress and egress over the remainder of the Lands to and from SRW Area for Trans Mountain, its personnel, equipment, contractors and agents for all purposes necessary or incidental to the exercise and enjoyment of the rights herein granted. across, over, under, in, through or on the SRW Area.

The rights and statutory right of way hereinbefore granted shall take effect as and from the date hereof on the following terms and conditions which are hereby mutually agreed to:

1. Trans Mountain shall pay the compensation to the Owner for the grant of Statutory Right of Way as follows:

   Delete (a) or (b):

   (a) one lump sum payment of ___________________________Dollars ($__________), plus applicable taxes (initial)

   or

   (b) by annual or periodic payments of equal or different amounts over a period of time as set forth in Schedule One attached hereto and forming part hereof; (initial)

   If the Lump Sum Payment option is chosen (option 1(a)), such payment shall be made on or before construction of the Pipeline is commenced on the Lands. If option 1(b) is chosen the first of such payments shall commence on or before construction of the Pipeline is commenced on the Lands.

   [Optional] In the event that the lump sum payment, or the first annual or periodic payment, as the case may be, has not been made before__________________, 20_______, then the Statutory Right of Way shall terminate and be at an end for all purposes and Trans Mountain shall forthwith execute and register such documents as may be necessary to discharge this Agreement from the Indefeasible Title for the Lands and shall notify the Owner of the registration of the discharge.

2. The Owner shall have the right fully to use and enjoy the SRW Area subject to the rights of Trans Mountain under the Statutory Right of Way provided however that the Owner shall not, without the prior written consent of Trans Mountain, which consent shall not be unreasonably withheld, excavate, drill, install, erect, place, plant or permit to be excavated, drilled, installed, erected, placed, or planted on, over, under, across or through the SRW Area any pit, well, foundation, pavement, building, tree, crop other than an annual crop or any other structure, installation or object.

3. Notwithstanding the provisions of Clause 2, Trans Mountain will not object to the Owner:

   (i) paving existing farm lanes, private roads, driveways, and sidewalks across the SRW Area;

   (ii) erecting fences across the SRW Area or any portion thereof; or

   (iii) constructing drains or repairing drains on the SRW Area or any portion thereof;

   provided, however, that the Owner agrees to exercise a high degree of care in carrying out any excavation or drilling necessary for such fencing, paving or drainage, and in no event shall the Owner or his contractors perform such work in such a manner as to endanger or damage the Pipeline. Before the commencement of any such work, the Owner shall give to Trans Mountain at least five (5) days prior notice in writing so as to enable a representative of Trans Mountain to inspect the site of the proposed work and to advise how the work may be performed without damage to the Pipeline.

4. Trans Mountain will compensate the Owner for all damages suffered as a result of its operations.

5. Trans Mountain will, as soon as weather and soil conditions permit and insofar as it is practicable so to do, bury and maintain the Pipeline in a manner that will not interfere with the drainage or ordinary cultivation of the Lands, and will restore all drains damaged or disturbed by the operation, according to good drainage practice.

6. Notwithstanding that in constructing, maintaining and operating its Pipeline Trans Mountain may install pipe and other equipment and appurtenances in, on, over, under, across or through the SRW Area in such a manner that it or they become affixed to the Lands, the title to such pipe and other equipment and appurtenances shall until surrendered, remain in Trans Mountain. Trans Mountain may at any time remove the whole or any part of the Pipeline.

7. Upon the discontinuance of the use of the SRW Area and of the exercise of the rights hereby granted, Trans Mountain shall and will restore the SRW Area to the same condition, so far as it is practicable so to do, as the same were in prior to the entry thereon and the use thereof by Trans Mountain. Trans Mountain agrees to withdraw and discharge any registrations at the Land Title Office pertaining to the Statutory Right of Way upon its abandonment of the SRW Area.

8. Trans Mountain in performing and observing the covenants and conditions contained in this Agreement, shall peaceably hold and enjoy the rights and Statutory Right of Way hereby granted without hindrance, molestation or interruption on the part of the Owner or of any person, firm or corporation claiming by, through, under or in trust for the Owner.

9. Trans Mountain shall have the absolute right to assign the Statutory Right of Way in whole or in part, and upon such assignment, shall give to the Owner written notice thereof within ten (10) days, but Trans Mountain need not give such notice upon assignment in the course of its corporate financing by way of a deed of trust, mortgage, debenture or a floating charge or upon assignment arising out of an amalgamation or merger.

10. This Agreement shall not affect or prejudice Trans Mountain's statutory rights to acquire a right of entry or any portion of the Lands under the provisions of the *National Energy Board Act* (the "**Act**"), or any other laws, which rights may be exercised at Trans Mountain's discretion.

11. The Owner will, if so requested by Trans Mountain, execute such further documents of title and assurances in respect of the Statutory Right of Way as may be required to perfect Trans Mountain's interest in the Lands under this Instrument.

12. Nothing contained herein shall vest in Trans Mountain any title to mines or minerals in or under the Lands or any part, except only as may be included in any rock, stone or soil that

are necessary to be excavated, carried away or used in the construction of the Pipeline belonging to Trans Mountain.

13. Where Trans Mountain requires an above ground installation of the Pipeline upon the SRW Area (other than pipeline markers installed at property or fence lines) or requires any part of the SRW Area to be fenced, the Owner shall be entitled to additional compensation to be agreed upon between the parties, or failing agreement, pursuant to the procedure available for negotiation and arbitration under Part V of the Act.

14. Trans Mountain will not object to any application made by the Owner under Section 112 of the Act so long as the proposed crossing is made in accordance with good engineering practice and does not interfere with the operation of the Pipeline.

15. This Agreement is a covenant running with the Lands and the provisions of this Agreement shall extend to, be binding upon, and ensure to the benefit of the heirs, executors, administrators, successors and assigns of the Owner and Trans Mountain, respectively.

16. Wherever the singular or masculine is used in this Agreement, it shall be construed as if the plural or feminine or the neuter, as the case may be, had been used where the context so requires.

17. It is agreed that the Owner shall have the right to transfer or convey his interest in the Lands and the covenants and conditions herein contained in one or more parcels and by one or more conveyances and that all the covenants and conditions herein contained shall extend to and be binding upon and ensure to the benefit of each and all of the heirs, executors, administrators, successors, and assigns of the Owner in respect of each and every parcel transferred or conveyed.

18. All notices to be given hereunder may be given by registered letter addressed to Trans Mountain, Suite 2700, Stock Exchange Tower 300 – 5th Avenue S.W., Calgary, Alberta, T21 5J2, and to the Owner at ________________________________ or such other address as Trans Mountain and the Owner may respectively appoint, from time to time, in writing, and any such notice shall be deemed to be given to and received seven (7) days after the mailing thereof, postage prepaid.

19. Trans Mountain will only install an additional pipeline or pipelines in the SRW Area with the consent and agreement of the Owner, or, in the absence of such consent and agreement, in accordance with all authorizations and determinations, including with respect to any additional compensation payable, made under the Act.

20. The Owner agrees that Trans Mountain may, at its option, at any time in the course of operating the Pipeline enter upon the SRW Area with men and equipment and remove all shrubs and trees from the SRW Area.

21. Trans Mountain shall indemnify the Owner from all liabilities, damages, claims, suits and actions arising out of the operations of Trans Mountain other than liabilities, damages, claims, suits and actions resulting from the gross negligence or willful misconduct of the Owner.

22. The Owner confirms having the option of requiring the compensation for the rights herein granted to be made by one lump sum payment or by annual or periodic payments of equal or different amounts over a period of time and that the Owner has selected the method of compensation hereinbefore set out. The Owner further confirms that if the Owner has selected annual or other periodic payments, the amount of such compensation payable by Trans Mountain shall be reviewed every five (5) years if the period of compensation extends beyond five (5) years.

23. The Owner consents to the collection and use of his/her personal information within this Instrument. Trans Mountain collects this type of personal information for the purposes of general land rights acquisition and regulatory disclosure. The Owner consents to the collection, use and disclosure of its personal information for these legitimate business purposes in relation to land matters of Trans Mountain.

24. The Owner acknowledges receipt of a notice given pursuant to Section 87(1) of the Act and given prior to the entering into of this Agreement, setting out or accompanied by:

    (a) a description of the lands of the Owner required by Trans Mountain for a section or part of the Pipelines;

    (b) details of the compensation offered by Trans Mountain for such lands required;

    (c) a detailed statement made by Trans Mountain of the value of such lands required in respect of which compensation was offered;

    (d) a description of the procedure for approval of the detailed route of Trans Mountain's Pipelines; and

    (e) a description of the procedure available for negotiation and arbitration under Part V of the Act in the event that the Owner and Trans Mountain are unable to agree on any matter respecting the compensation payable.

25. The Owner acknowledges that Trans Mountain has explained the specific route of the proposed pipeline right of way, as well as the proposed methods and timing of the construction of the Pipeline that will be installed therein. This Agreement confirms that the Owner is in agreement with the location of the pipeline right of way, and the methods and timing of construction of the Pipeline that will be installed therein. The Owner hereby waives any right to ask for a hearing to settle the detailed Pipeline route or the methods and timing of construction, and understands that Trans Mountain may not serve the Owner with further Notice of the detailed route of the Pipeline pursuant to Section 34 (1)(a) of the Act.

IN WITNESS WHEREOF the Owner and Trans Mountain have executed and delivered these presents as of the day and year first above written, on Part 1 of the Form C General Instrument attached to and forming part of this Instrument.

ATTACHED TO AND FORMING PART OF THE STATUTORY RIGHT OF WAY AGREEMENT

SCHEDULE ONE

Annual or Periodic Payment

The consideration for this Agreement is the sum of Dollars ($__________) of lawful money of Canada to be paid on or before construction is commenced on the Lands, the receipt of which is hereby acknowledged by the Owner, and thereafter the sum of Dollars ($__________) of lawful money of Canada to be paid on or before the anniversary date thereafter for a period of __________ (__________) years. The amount of any annual or periodic payment will be reviewed every five (5) years if the period of compensation extends beyond five (5) years.

The Owner hereby agrees to and accepts the annual or periodic payment set out above.

Witness:	Owner:
Witness:	Owner:
Witness:	Owner:

Appendix G Agreement for Temporary Working Space, Province of Alberta

TRACT:
GST Reg. No:

AGREEMENT FOR TEMPORARY WORKING SPACE
PROVINCE OF ALBERTA

This Agreement dated the______ day of___________________, 20____ (the "**Effective Date**").

BETWEEN:

____ (the "**Owner**")

- and -

TRANS MOUNTAIN PIPELINE L.P.by the General Partner TRANS MOUNTAIN PIPLINE ULC

WHEREAS the Owner is registered as owner or entitled to become registered as owner of an estate in fee simple, subject however to such encumbrances, liens and interests as appear on the Certificate of Title, in all that certain tract of land situated in the Province of Alberta being composed of:
____ (the "**Lands**");

AND WHEREAS Trans Mountain has acquired an easement and right of way from the Owner through the Lands for the purpose of constructing two (2) pipelines and other incidental facilities (the "**Pipelines**") all as more particularly described in an Agreement for Easement between the Owner and Trans Mountain;

AND WHEREAS Trans Mountain requires the right to use a portion of the Lands adjacent to its right of way as shown on the attached property sketch (and identified as "**Temporary Working Rights**" and /or "**Extra Temporary Working Rights**") to facilitate the construction of the Pipelines ("**Temporary Working Space**");

AND WHEREAS the Owner is willing to grant to Trans Mountain the use of the Temporary Working Space for and in consideration of the covenants and payments hereinafter set out;

NOW THEREFORE, the parties hereto agree as follows:

1. The sum of ____ Dollars ($___________), plus *Goods and Services Tax*, shall be paid to the Owner before construction of the Pipelines is commenced on the Lands.

2. The Owner hereby grants to Trans Mountain, its employees, agents, contractors, subcontractors, successors and assigns, the right, license, liberty and privilege to clear, enter and use the Temporary Working Space with people, vehicles, supplies, and equipment from the Effective Date until completion of final reclamation and clean-up, for all purposes useful or convenient in connection with or incidental to the exercise and enjoyment of the rights and privileges provided for in the Agreement for Easement.

3. Trans Mountain shall compensate the Owner for all damage resulting from the use of the Temporary Working Space by Trans Mountain, its employees, agents, contractors, and subcontractors.

4. When Trans Mountain no longer requires the use of the Temporary Working Space and the rights hereby granted, and as soon as it is reasonably practical to do so, Trans Mountain shall restore the surface of the Temporary Working Space in accordance with all applicable laws and regulations.

5. This Agreement, including all covenants and conditions herein contained, shall extend to, be binding upon and enure to the benefit of the heirs, executors, administrators, successors and assigns of the Owner and Trans Mountain. In the event the Owner transfers his/her ownership in the Lands, the Owner agrees to provide fifteen (15) days prior notice of said transfer to Trans Mountain. Such notice shall include the name of the Owner, the legal description of the Lands, the name of the transferee, and the effective date of the transfer. If made in writing, the notice shall be mailed to Trans Mountain, Suite 2700, Stock Exchange Tower 300 – 5th Avenue S.W., Calgary, Alberta, T21 5J2, and shall be deemed to have been given to and received by Trans Mountain seven (7) days after the mailing thereof. Alternatively, the Owner may affect such notice by leaving a detailed message at ***[NTD: insert Trans Mountain toll-free phone number]***.

6. Trans Mountain may, at any time for whatsoever reason or cause, at its election on notice in writing to the Owner, terminate this Agreement, and upon giving such notice, this Agreement shall be of no further effect and Trans Mountain shall stand relieved of all of its obligations hereunder other than those which accrued prior to the date of termination.

7. Trans Mountain shall indemnify and save harmless the Owner from any and all liabilities, damages, claims, suits or actions arising out of the use of the Temporary Working Space by Trans Mountain, its employees, agents, contractors, and subcontractors, other than liabilities, damages, claims, suits and actions resulting from the negligence or willful misconduct of the Owner. Notwithstanding the foregoing, Trans Mountain shall not in any event be liable for any indirect or consequential damages.

8. Trans Mountain and the Owner hereby agree and acknowledge that this Agreement does not create a lease and does not constitute a right or interest in land.

IN WITNESS WHEREOF the parties have executed and delivered this Agreement as of the date first above written.

Witness:	Owner:
Witness:	Owner:

TRANS MOUNTAIN PIPELINE L.P. by the General Partner TRANS MOUNTAIN PIPLINE ULC

Per: ________________________________

____

Print name and position

Per: ________________________________

____

Print name and position

Appendix H Agreement for Temporary Working Space, Province of British Columbia

TRACT:
GST Reg. No:

AGREEMENT FOR TEMPORARY WORKING SPACE
PROVINCE OF BRITISH COLUMBIA

This Agreement dated the ______day of __________________, 20 ____ (the "**Effective Date**").

BETWEEN:

____ (the "Owner")

- and –

TRANS MOUNTAIN PIPELINE L.P.
("Trans Mountain")

WHEREAS the Owner is registered as owner of an estate in fee simple, subject however to such encumbrances, liens and interests as appear on the Indefeasible Title, in all that certain tract of land situated in the Province of British Columbia described as:
____ (the "**Lands**");

AND WHEREAS Trans Mountain has acquired a Statutory Right of Way from the Owner over part of the Lands (the "**SRW Area**") for the purpose of constructing a pipeline (the "**Pipeline**") all as more particularly described in a Statutory Right of Way Agreement between the Owner and Trans Mountain;

AND WHEREAS Trans Mountain requires the right to use a portion of the Lands adjacent to the SRW Area as shown on the attached property sketch (and identified as "**Temporary Working Rights**" and /or "**Extra Temporary Working Rights**") to facilitate the construction of the Pipeline ("**Temporary Working Space**");

AND WHEREAS the Owner is willing to grant to Trans Mountain the use of the Temporary Working Space for and in consideration of the covenants and payments hereinafter set out;

NOW THEREFORE, the parties hereto agree as follows:

1. The sum of ____Dollars ($__________), *plus applicable taxes*, shall be paid to the Owner before construction of the Pipeline is commenced on the Lands (the date of such payment the "**Effective Date**").

2. The Owner hereby grants to Trans Mountain, its employees, agents, contractors, subcontractors, successors and assigns, the right, license, liberty and privilege to clear, enter and use the Temporary Working Space with people, vehicles, supplies, and equipment from the Effective Date until completion of the construction and installation of the Pipeline within the Lands and final reclamation as provided below, for all purposes useful or convenient in connection with or incidental to the exercise and enjoyment of the rights and privileges provided for in the Statutory Right of Way Agreement.

3. Trans Mountain shall compensate the Owner for all damage resulting from the use of the Temporary Working Space by Trans Mountain, its employees, agents, contractors, and subcontractors.

4. *[When Trans Mountain no longer requires the use of the Temporary Working Space and the rights hereby granted, and as soon as it is reasonably practical to do so,]* Upon the completion of the construction and installation of the Pipeline within the Lands or any abandonment of such work Trans Mountain shall restore the surface of the Temporary Working Space to the extent it is practicable to do so in accordance with all applicable laws and regulations.

5. This Agreement, including all covenants and conditions herein contained, shall extend to, be binding upon and enure to the benefit of the heirs, executors, administrators, successors and assigns of the Owner and Trans Mountain. In the event the Owner transfers his/her ownership in the Lands, the Owner agrees to provide fifteen (15) days prior notice in writing of said transfer to Trans Mountain. Such notice shall include the name of the Owner, the legal description of the Lands, the name of the transferee, and the effective date of the transfer. The notice shall be mailed to Trans Mountain, Suite 2700, Stock Exchange Tower 300 – 5th Avenue S.W., Calgary, Alberta, T21 5J2, and shall be deemed to have been given to and received by Trans Mountain seven (7) days after the mailing thereof. Alternatively, the Owner may affect such notice by leaving a detailed message at ***[NTD: insert Trans Mountain toll-free phone number]***.

6. Trans Mountain may, at any time *[prior to the Election Date?]* for whatsoever reason or cause, at its election on notice in writing to the Owner, terminate this Agreement, and upon giving such notice, this Agreement shall be of no further effect and the Company shall stand relieved of all of its obligations hereunder other than those which accrued prior to the date of termination.

7. Trans Mountain shall indemnify and save harmless the Owner from any and all liabilities, damages, claims, suits or actions arising out of the use of the Temporary Working Space by Trans Mountain, its employees, agents, contractors, and subcontractors, other than liabilities, damages, claims, suits and actions resulting from the gross negligence or wilful misconduct of the Owner.

8. Trans Mountain and the Owner hereby agree and acknowledge that this Agreement does not create a lease and does not constitute a right or interest in land.

IN WITNESS WHEREOF the parties have executed and delivered this Agreement as of the date first above written.

Witness:	Owner:
Witness:	Owner:
Witness:	Owner:

TRANS MOUNTAIN PIPELINE L.P. by its General Partner TRANS MOUNTAIN PIPELINE ULC

Per: ____________________________

____
Print name and position

Per: ____________________________

____
Print name and position

Appendix I Option to Purchase Agreements for BC and Alberta

Tract ____________________
GST Registration No.____________________

OPTION TO PURCHASE - ALBERTA

THIS AGREEMENT dated the ____ day of ___________________, 20___.

BETWEEN:

TRANS MOUNTAIN PIPELINE L.P. by the General Partner TRANS MOUNTAIN ULC
("Trans Mountain")
– and –

____
(the "**Owner**")

WHEREAS:

A. The Owner is the registered owner of certain lands in or near ___________________, in the Province of Alberta, more particularly described as follows:

[insert legal description]

subject to the reservations and exceptions appearing in the existing Certificate of Title attached as Schedule "A" (the "**Property**");

B. Trans Mountain wishes to acquire lands as substantially shown on the plan attached as Schedule "B" (the "**Option Lands**"); and

C. The Owner has agreed to grant to Trans Mountain an option to purchase the Option Lands pursuant to the terms, provisions and conditions set forth in this Agreement.

In consideration of the sum of ____ Dollars ($___________________), exclusive of Goods and Services Tax (the "**Consideration**") now paid by Trans Mountain to the Owner, receipt of which the Owner hereby acknowledges, the Owner and Trans Mountain agree as follows:

Grant of Option to Purchase

1. The Owner hereby grants to Trans Mountain the sole and exclusive option to purchase the Option Lands (the "**Option**") irrevocable within the time for exercise provided in Section 2 herein for the Purchase Price and on and subject to the terms and conditions set forth in this Agreement.

Exercise of Option

2. The Option may be exercised by Trans Mountain by notice in writing delivered or mailed to the Owner on or before 5:00 p.m. Mountain Standard Time on ___________________, _____, 20____.

3. Notice in writing mailed to the Owner of the exercise of the Option by Trans Mountain shall be deemed effective at the time and date such notice is mailed by Registered Mail addressed to the Owner at ____________________________in the Province of _____________________.

4. In the event that Trans Mountain does not exercise the Option, this Agreement shall be null and void and no longer binding on the parties, except the Owner shall be entitled to retain the Consideration.

Purchase Price

5. If the Option is exercised, Trans Mountain shall pay to the Owner compensation constituting the Purchase Price as hereinafter set out for the Option Lands. The Consideration paid to the Owner shall be credited towards the Purchase Price.

6. If the Option is exercised by Trans Mountain, Trans Mountain shall pay to the Owner a purchase price for the Option Lands calculated as follows:

   (a) one lump sum of ______________________________________ Dollars ($_______________) per hectare ($___________________ per acre) multiplied by the area of the Option Lands in hectares (acres) determined, if required by either party, by a legal survey, (the "**Lump Sum Payment**") plus Goods and Services Tax ("**GST**"),

   (b) annual or periodic payments of equal or different amounts over a period of time as set forth in Schedule "C".

   (the "**Purchase Price**")

7. The parties agree that on the Closing Date the Owner shall not collect GST from Trans Mountain in respect of the purchase and sale of the Option Lands, and Trans Mountain shall file returns and remit GST to the Canada Revenue Agency in respect of the purchase and sale of the Option Lands when and to the extent required by the *Excise Tax Act*. Trans Mountain shall provide the Owner a statutory declaration on closing confirming its GST registration number under the *Excise Tax Act* and any other matters reasonably required by the Owner.

8. Upon the exercise of the Option, this Agreement and the document by which the Option is exercised shall become a binding contract of sale and purchase and such sale and purchase shall be completed upon the terms provided herein.

Closing

9. On and subject to the terms and conditions hereof, vacant possession of the Option Lands shall be provided to Trans Mountain and the title to the Option Lands shall be transferred to Trans Mountain in accordance with Section 11 on the closing date, which shall be the last day of the 3rd month following the later of the month in which the Option is exercised, or the date upon which unconditional subdivision approval, if applicable, has been granted by the subdivision approval authority (the "**Closing Date**").

10. The Owner shall provide to Trans Mountain, in registerable form, a transfer of land, a statement of adjustments, and other conveyancing documents in a reasonable time prior to the Closing Date in order for Trans Mountain to confirm registration on or before the Closing Date.

11. On the Closing Date, Trans Mountain shall pay to the Owner, by cheque, the Lump Sum Payment or the first payment referred to in Schedule "C", subject to a credit in Trans Mountain's favor for the Consideration toward such payment and also subject to all usual adjustments including for rents, taxes, and interest, if any. The payment shall be held in trust by the Owner's solicitor until:

    (a) title to the Option Lands has been issued in the name of Trans Mountain, subject only to non-financial instruments on the title to the Option Lands such as easements, utility rights-of-way and covenants that are normally found registered against property of this nature, all of which shall be in good standing, and such non-financial encumbrances that have been specifically accepted by Trans Mountain in writing at the time of its exercise of the Option. Unless otherwise agreed to in writing, the title to the Option Lands shall be transferred to Trans Mountain free and clear of all other liens, encumbrances, caveats, instruments, registrations and obligations except those implied by statute, and

    (b) the Owner shall have delivered vacant possession of the Option Lands free and clear of any tenancy.

    The Owner shall be solely responsible and shall pay for all of the costs of discharging any existing lien, mortgage, encumbrance, caveat or other instrument which is not permitted under Section 11(a).

<u>Access</u>

12. Upon the granting of the Option, Trans Mountain, its employees, agents, contractors, and sub-contractors may enter upon the Property at the sole risk of Trans Mountain and make all surveys, soil tests, environmental and geotechnical investigations, and such other examinations as Trans Mountain deems appropriate. Trans Mountain shall compensate any tenant on the Property for any damage to the tenant's crops. Trans Mountain shall restore or pay for the restoration of any damage resulting from such activities if this Option is not exercised.

<u>Representations and Warranties</u>

13. Notwithstanding any investigations of Trans Mountain, the Owner makes, and Trans Mountain is entitled to rely upon, the following representations and warranties in respect of the Property and the Option Lands both as of the date hereof and as of the Closing Date:

    (a) the Owner is not now, nor will the Owner be within sixty (60) days after the Closing Date, a non-resident of Canada for purposes of Section 116 of the *Income Tax Act* of Canada;

(b) the Owner is not aware of any contamination of or other adverse environmental concern related to the Option Lands or the Property;

(c) There are no actions, suits or proceedings commenced or, to the knowledge of the Owner, threatened against or affecting the Owner or the Option Lands or the occupancy or use of the Option Lands by the Owner, in law or in equity, which could affect the validity of this Agreement, the title to the Option Lands, the conveyance of the Option Lands to Trans Mountain, or the right of Trans Mountain from and after the Closing Date to own and develop the Option Lands;

(d) The Owner is not aware of any proposed expropriation of any part of the Option Lands;

(e) No person, firm or corporation (other than Trans Mountain) has any agreement or option or any right capable of becoming an agreement or option for the purchase of all or any part of the Option Lands;

(f) to the best of the Owner's knowledge, information and belief the Option Lands has not been subject to any prior use which might reasonably be expected to have resulted in deleterious or hazardous substances having been deposited or accumulated upon, within, or under the Option Lands; and

(g) the Option Lands are not subject to or affected by any encumbrances or adverse interests except as set out in Section 11 above, and also free and clear from any charges, claims or obligations of any party claiming by, through or under the Owner.

14. Without limiting the foregoing representations and warranties, Trans Mountain acknowledges that:

(a) it is relying on its own investigations, analysis, appraisals, and estimates as to the value of the Option Lands and the suitability of the Option Lands for the use it intends; and

(b) it is obtaining all required regulatory and other approvals, including planning, development, zoning and building approvals and permits.

Conditions Precedent

15. The following conditions shall be conditions precedent to Trans Mountain's obligation to complete the purchase of the Option Lands following exercise of the Option:

(a) Trans Mountain shall be satisfied, in its sole discretion, that all approvals or permits whatsoever, including without limitation, zoning, subdivision, regulatory, environmental, development and building permits, shall have been obtained or are obtainable on terms acceptable to it, in order for it to acquire the Option Lands and develop the Option Lands in accordance with its intended use;

(b) Trans Mountain shall be satisfied, in its sole discretion, that environmental and geo-technical investigations do not reveal any conditions that would make the Option Lands unsuitable for its intended use;

(c) the Owner's representations and warranties shall be true and not misleading in any way and Trans Mountain shall not have become aware of any fact or thing which would reasonably lead it to believe otherwise; and

(d) the Owner shall have complied with Section 13.

16. If Trans Mountain has not delivered written notice to the Owner that the conditions precedent described in Section 15 have all been satisfied fourteen (14) days prior to the Closing Date, or Trans Mountain does not waive them, this Agreement shall terminate and be of no further force and effect.

17. If applicable, Trans Mountain shall have received subdivision approval in respect of the subdivision of the Option Lands from the Property from the subdivision approval authority by no later than ___________________________, and in the event approval is not obtained by this date, the Agreement shall terminate and be of no further force and effect.

Miscellaneous

18. The parties agree that the Consideration does not include GST of ____________________ and that the Owner shall not collect GST from Trans Mountain in respect of the Consideration, and Trans Mountain shall file returns and remit GST to the Canada Revenue Agency in respect of the Consideration when and to the extent required by the *Excise Tax Act*.

19. The Owner agrees not to remove or allow the removal of any materials from the Option Lands (including any soil) while this Agreement remains in effect, or otherwise alter the Option Lands, or the use of the Option Lands, which may result in a material adverse impact on the Option Lands, or the use of the Option Lands by Trans Mountain, and the Owner shall deliver possession of the Option Lands in substantially the same condition as existed at the date of this Agreement.

20. The Owner shall execute all further deeds, documents and assurances, and shall do all such further things as may be reasonably required for the purpose of carrying out this Agreement according to its true meaning and intent.

21. This Agreement shall be binding upon and enure to the benefit of the heirs, executors, administrators, successors and assigns of the Owner and Trans Mountain, respectively.

22. If any provision contained in this Option or its application to any party hereto or circumstance shall, to any extent, be invalid or unenforceable, the remainder of this Option or the application of such provision to such parties or circumstances other than those to which it is held invalid or unenforceable shall not be affected.

23. Trans Mountain shall be responsible for:

(a) all costs related to the obtaining of subdivision approval of the Option Lands, if applicable;

(b) the costs of a legal survey of the Option Lands; and

(c) the costs for the preparation and registration of any legal property or subdivision plans.

24. The Option Lands including all fixtures and other items to be purchased related to the Option Lands shall remain at the risk of the Owner until the Closing Date. In the event of loss, destruction or damage or any such property between the granting of the Option and the Closing Date, at Trans Mountain's option, either such loss will be repaired and corrected at the expense of the Owner, except to the extent that such loss is directly due to the actions of Trans Mountain or its representatives, or such loss will be dealt with in an equitable manner by way of an adjustment at closing.

25. Trans Mountain shall have the right at any time and from time to time to assign all of its rights and obligations under this Agreement. The Owner shall not, in whole or in part, assign his interest in this Agreement without the prior written consent of Trans Mountain.

26. Time shall be of the essence. The provisions hereof shall survive the registration of all conveyances and shall not merge therein or therewith.

27. The Agreement shall be governed by and interpreted in accordance with the laws of the Province of Alberta.

28. This Agreement shall enure to the benefit of, and be binding upon, the parties hereto and their respective successors and assigns.

29. The Owner acknowledges receiving a Notice pursuant to Section 87 (1) of the *National Energy Board Act* concerning the above property.

30. The Owner confirms having the option of requiring the Purchase Price to be made by one Lump Sum Payment or by annual or periodic payments of equal or different amounts over a period of time and that the Owner has selected the method of compensation hereinbefore set out. The Owner and Trans Mountain further confirm that if the Owner has selected annual or other periodic payments, the amount of such compensation payable to the Owner shall be reviewed every five years if the period of compensation extends beyond five years.

31. Until the Closing Date, Trans Mountain agrees as follows:

(a) to pay compensation for all damages suffered by the Owner as a result of the operations of Trans Mountain on the Property;

(b) to indemnify the Owner from all liabilities, damages, claims, suits and actions arising out of the operations of Trans Mountain on the Property other than liabilities, damages, claims, suits and actions resulting from the gross negligence or wilful misconduct of the Owner;

(c) that any use of the Option Lands by Trans Mountain shall be restricted to the purposes set out in Section 12, unless the Owner consents to any proposed additional use at the time of the proposed additional use.

IN WITNESS WHEREOF the parties hereto have duly executed this Agreement by their respective hands as of the day and year first above written.

Witness:	Owner:
Witness:	Owner:

TRANS MOUNTAIN PIPELINE L.P. by the General Partner TRANS MOUNTAIN PIPLINE ULC

Per: ______________________________

____
Print name and position

Per: ______________________________

____
Print name and position

SCHEDULE "A"

SCHEDULE “B”

SCHEDULE "C"

The Purchase Price is the sum of ________________________________ Dollars ($______________________) of lawful money of Canada to be paid before construction is commenced on the said Option Lands and thereafter the sum of ___________________________ Dollars ($______________________) of money of Canada to be paid in each and every year. This annual payment shall be made on or before the anniversary date of the first payment being made before construction is commenced, for a period of ___ years ("**term**").

ALBERTA – THE DOWER ACT
CONSENT OF SPOUSE

I, ____,
being married to the within named ______________________ do hereby give my consent to the disposition of our homestead, made in the within instrument, and I have executed this document for the purpose of giving up my life estate and other dower rights in the said property given to me by THE DOWER ACT, to the extent necessary to give effect to the said disposition.

____

CERTIFICATE OF ACKNOWLEDGEMENT BY SPOUSE

1. This document was acknowledged before me by ____________________ apart from her husband (his wife).

2. ______________________________________ acknowledged to
me that she (he)

    (a) is aware of the nature of the disposition or agreement;

    (b) is aware that THE DOWER ACT, gives her (him) a life estate in the homestead and the right to prevent disposition of the homestead by withholding consent;

    (c) consents to the disposition or agreement for the purpose of giving up the life estate and other dower rights in the homestead given to her (him) by THE DOWER ACT, to the extent necessary to give effect to the said disposition or agreement;

    (d) is executing the document freely and voluntarily without any compulsion on the part of her husband (his wife).

SWORN before me at the ______________)
of ____________________ in the)
Province of Alberta, this ___ day of)
______________, A.D. 20___) ____________________________
)
______________________________)
A Commissioner for Oaths in and for the)
Province of Alberta)

AFFIDAVIT

CANADA
PROVINCE OF ALBERTA
TO WIT:

I, ____ of __________________________, in the Province of Alberta, ____________________________________, make oath and say:

1. That I am the Grantor named in the within instrument.

2. That I am not married.

   -OR-

   That neither myself nor my spouse have resided on the within mentioned land at any time since our marriage.

SWORN before me at the _______________)	
of ______________________________ in the)	
Province of Alberta, this ___ day of)	
________________, A.D. 20___)	____
)	
____)	
A Commissioner for Oaths in and for the)	
Province of Alberta)	

AFFIDAVIT OF EXECUTION

CANADA	)	I, ____________________________ of the
	)	
PROVINCE OF ALBERTA	)	_________________ of _______________
	)	
TO WIT:	)	in the Province of Alberta

MAKE OATH AND SAY:

1. THAT I was personally present and did see __________________________________ named in the within instrument, who is (are) personally known to me to be the person(s) named therein, duly sign, seal and execute the same for the purpose named therein.

2. THAT the instrument, was executed at the ____________________________________, of _____________________________ in the Province of Alberta, and that I am the subscribing witness thereto.

3. THAT I believe the person(s) whose signatures I witnessed is (are) at least eighteen (18) years of age.

SWORN before me at the ______________	)	
of _____________________________ in the	)	
Province of Alberta, this ___ day of	)	
_______________, A.D. 20___	)	______________________________________
	)	
______________________________________	)	
A Commissioner for Oaths in and for the	)	
Province of Alberta	)	

Tract ___________________
GST Registration No. of Trans Mountain_____________________

OPTION TO PURCHASE - BRITISH COLUMBIA

THIS AGREEMENT dated the _______ day of ____________________, 20__.

BETWEEN:

TRANS MOUNTAIN PIPELINE L.P.
("Trans Mountain")
– and –

____
(the "**Owner**")

WHEREAS:

A. The Owner is the registered owner of certain lands in or near ___________________, in the Province of British Columbia, more particularly described as follows:

[insert legal description]

subject to the rights of way, easements and covenants in favour of utilities and public authorities as set out in Schedule "A" (the "**Property**");

B. Trans Mountain wishes to purchase part of the Property (the "**Option Lands**") substantially as shown on the plan attached as Schedule "B" (the "**Option Lands Plan**"); and

C. The Owner has agreed to grant to Trans Mountain an Option to Purchase the Option Lands pursuant to the terms, provisions and conditions set forth in this Agreement.

In consideration of the sum of ____ Dollars ($____________________), exclusive of Goods and Services Tax (the "**Consideration**") now paid by Trans Mountain to the Owner, receipt of which the Owner hereby acknowledges, the Owner and Trans Mountain agree as follows:

Grant of Option to Purchase

1. The Owner hereby grants to Trans Mountain the sole and exclusive option to purchase the Option Lands, irrevocable within the time for exercise provided in Section 2 herein, on the terms and conditions hereinafter set forth ("Option").

Exercise of Option

2. The Option may be exercised by Trans Mountain by notice in writing delivered or mailed on or before 5:00 p.m. Vancouver time on ______________________, _____, 20____.

3. Notice in writing mailed to the Owner of the exercise of the Option by Trans Mountain shall be deemed effective at the time and date such notice is mailed by Registered Mail addressed to the Owner at ______________________________________ in the Province of British Columbia.

4. In the event that Trans Mountain does not exercise the Option, this Agreement shall be null and void and no longer binding on the parties, except the Owner shall be entitled to retain the Consideration.

Purchase Price

5. If the Option is exercised, Trans Mountain shall pay to the Owner compensation constituting the purchase price ("**Purchase Price**") for the Option Lands. The Consideration paid to the Owner shall be credited towards the Purchase Price.

6. If the Option is exercised by Trans Mountain, Trans Mountain shall pay to the Owner the Purchase Price for the Option Lands which shall be the sum of $________________ per hectare ($_______________ per acre) multiplied by the area of the Option Lands in hectares (acres) determined by a legal survey carried out for the Section 114 Plan (hereinafter defined), plus Goods and Services Tax ("**GST**").

7. The parties agree that on the Closing Date (as defined herein) the Owner shall not collect GST from Trans Mountain in respect of the purchase and sale of the Option Lands, and Trans Mountain shall file returns and remit GST to the Canada Revenue Agency in respect of the purchase and sale of the Option Lands when and to the extent required by the *Excise Tax Act*.

8. Upon the exercise of the Option, this Agreement and the document by which the Option is exercised shall become a binding contract of sale and purchase and such sale and purchase shall be completed upon the terms provided herein.

Permitted Encumbrances

9. The Option Lands will be free and clear of any encumbrances except the rights-of-way, easements and covenants in favour of utilities and public authorities set out in Schedule "A" to this Agreement (together the "**Permitted Encumbrances**").

Closing

10. The closing date (the "**Closing Date**") shall be the last day of the third month following the month in which the Option is exercised.

11. Trans Mountain covenants that prior to the Closing Date it shall cause to be prepared a plan of survey capable of being deposited in the land title office for the Property under Section 114 of the *Land Title Act* concurrently with the registration of the Form A, so as to effect, without approval by the approving officer under the *Land Title Act*, the subdivision of the Option Lands from the Property in the records of the land title office and the creation of a separate parcel for the Option Lands with an indefeasible title issued in the name of Trans Mountain (such plan the "**Section 114 Plan**").

12. On or before the Closing Date, the Owner will deliver to Trans Mountain's solicitors <@> ("**Trans Mountain's Solicitors**"), on condition that the same will only be dealt with in accordance with Section 15 of this Agreement, the following documents duly signed, declared, executed (in registrable form where required) in accordance with their respective terms and the tenor thereof:

    (a) a Form A transfer document for the Option Lands in registrable form, executed by the Owner and transferring the Option Lands to Trans Mountain Pipeline ULC (the "**Form A**");

    (b) a statement of adjustments;

    (c) a statutory declaration of the Owner that the Owner is not a non-resident of Canada for the purposes of the *Income Tax Act* (Canada); and

    (d) such further deeds, acts, things, certificates and assurances as may be requisite in the reasonable opinion of Trans Mountain's Solicitors for more perfectly and absolutely assigning, transferring and conveying to Trans Mountain title to the Option Lands free and clear of any lien, charge, encumbrance or legal notation, other than the Permitted Encumbrances.

13. On or before the Closing Date, Trans Mountain will duly execute, as appropriate, and deliver to Trans Mountain's Solicitors the following:

    (a) a bank draft, certified cheque or solicitors trust cheque representing the Purchase Price subject to a credit in Trans Mountain's favour for the Consideration toward such payment and also subject to all adjustments as provided for in the statement of adjustments aforesaid (the "**Net Purchase Price**");

    (b) a certificate of an authorized officer of Trans Mountain confirming Trans Mountain's status as a GST registrant under the *Excise Tax Act* and any other matters reasonably required by the Owner; and

    (c) the necessary documents for the deposit in the land title office for the Property of the Section 114 Plan.

14. All of the closing documents contemplated in Sections 12 and 13 will be prepared by Trans Mountain's Solicitors and delivered to the Owner's solicitors at least five business days prior to the Closing Date. All documents referred to in Sections 12 and 13 shall be in the form and substance reasonably satisfactory to the solicitors for the party entitled to delivery thereof.

15. Forthwith following the deliveries required under Section 12 and 13 having been completed Trans Mountain's Solicitors shall cause application for the registration of the Form A and for deposit of the Section 114 Plan to be made to the land title office for the Property and on receipt of a satisfactory application title search for the Property that evidences in the ordinary course of the operation of such land title office an indefeasible title will issue to the Option Lands in the name of Trans Mountain subject only to:

(a) the Permitted Encumbrances; and

(b) any existing financial encumbrances granted by the Owner to be discharged in accordance with the procedure set out in Section 16 below,

Trans Mountain's Solicitors will pay to the Owner's solicitors by certified cheque or solicitor's trust cheque the Net Purchase Price

16. Notwithstanding anything contained herein to the contrary, if the Owner has existing financial charges which are to be discharged from title to the Option Lands after completion of the sale of the Option Lands to Trans Mountain, the Owner, while still required to cause the discharge of such charges, may wait to cause the discharge of the same until immediately after the receipt of the Purchase Price, but in this event, Trans Mountain shall pay the Net Purchase Price to the Owner's solicitor in trust, on undertakings to pay and discharge such financial charges from the Option Lands reasonably acceptable to Trans Mountain's Solicitors.

Adjustments

17. All usual adjustments of taxes, utilities, local improvement assessments, rent, security deposits, interest and all other charges and costs relating to the Option Lands, both incoming and outgoing, will be made as at the Closing Date. The Owner shall be responsible for all taxes, obligations and payments to the adjustment time, and Trans Mountain shall be responsible for all taxes, obligations and payments thereafter.

Possession

18. The Owner shall deliver vacant possession of the Option Lands to Trans Mountain on the Closing Date free and clear of any tenancy.

Risk

19. The Option Lands shall be at the risk of the Owner until 11:59 a.m. Vancouver Time on the Closing Date and thereafter at the risk of Trans Mountain.

Access

20. Upon the granting of the Option, Trans Mountain, its employees, agents, contractors, and sub-contractors may enter upon the Property at the sole risk of Trans Mountain and make all surveys, soil tests, environmental and geotechnical investigations, and such other examinations as Trans Mountain deems appropriate. Trans Mountain shall compensate any tenant on the Property for any damage to the tenant's crops resulting from Trans

Mountain's activities on the Property. Trans Mountain shall restore or pay for the restoration of any damage resulting from such activities if the Option is not exercised.

Subdivision

21. The Owner covenants with Trans Mountain that the Owner shall cooperate with Trans Mountain in obtaining all approvals or permits required for the subdivision of Option Lands from the Property including without limitation, all regulatory, environmental, developmental approvals (collectively, the "**Approvals**").

22. The Owner covenants with Trans Mountain that the Owner shall provide all consents required by Trans Mountain to allow for the Approvals and, if required, shall execute on behalf of Trans Mountain, or authorize the execution by Trans Mountain, of any applications, documents and instruments of any nature whatsoever in connection with the Approvals.

Representations and Warranties

23. Notwithstanding any investigations of Trans Mountain, the Owner makes, and Trans Mountain is entitled to rely upon, the following representations and warranties in respect of the Property and the Option Lands both as of the date hereof and as of the Closing Date:

   (a) the Owner is not a non-resident of Canada for purposes of Section 116 of the *Income Tax Act* of Canada;

   (b) the Owner is not aware of any contamination of or other adverse environmental concern related to the Option Lands or the Property;

   (c) to the best of the Owner's knowledge, information and belief the Property and the Option Lands have not been subject to any prior use which might reasonably be expected to have resulted in Hazardous Substances (as hereinafter defined) having been deposited or accumulated upon, within, or under the Option Lands or the Property or having been released from the Option Lands or the Property; and

   (d) the Owner has good and marketable title to the Option Lands, and is ready, willing and able to convey title to the Option Lands free and clear from any liens, encumbrances or adverse interests except the Permitted Encumbrances and any existing financial encumbrances granted by the Owner to be discharged in accordance with the procedure set out in Section 16, and also free and clear from any charges, claims or obligations of any party claiming by, through or under the Owner.

24. Without limiting the foregoing representations and warranties, Trans Mountain acknowledges that:

   (a) it is relying on its own investigations, analysis, appraisals, and estimates as to the value of the Option Lands and the suitability of the Option Lands for the use it intends; and

(b) it is obtaining all required Approvals.

Indemnity

25. The Owner covenants to indemnify and save harmless Trans Mountain and its agents, successors and assigns or any of them from and against any and all claims, actions, judgments, orders, suits, losses, damages, liabilities, fines, penalties, costs and expenses (including costs relating to environmental studies, investigations, excavations, inspections and remediation activities), and reasonable consultants, experts and legal fees and expenses as a result of or arising from:

(a) any act, omission, negligence or misconduct of the Owner or any person for whom the Owner is in law responsible that is not in compliance with any federal, provincial, municipal or other governmental or regulatory statutes, bylaws, regulations and rules relating to the environment, occupational safety, health or transportation ("**Environmental Laws**") in force on the Closing Date pertaining to the Option Lands or the Property or any activities conducted on the Option Lands or Property; or

(b) the release or presence upon, within, under or from the Option Lands or Property of any hazardous substance or pollutant or contaminant, toxic or dangerous waste, substance, chemical or material including, without limitation, gasoline and other petroleum substance or material which falls into the definition of waste, hazardous, toxic, dangerous goods or any variation of those terms or terms of similar import ("**Hazardous Substances**") under any Environmental Laws at or prior to the Closing Date; or

(c) as a result of any breach of the Owner of any of the representations and warranties and covenants of the Owner contained herein.

Conditions Precedent

26. The following conditions shall be conditions precedent to Trans Mountain's obligation to complete the purchase of the Option Lands following exercise of the Option:

(a) Trans Mountain shall be satisfied, in its sole discretion, that all Approvals have been obtained or are obtainable on terms acceptable to it, in order for it use the Option Lands in accordance with its intended use;

(b) Trans Mountain shall be satisfied, in its sole discretion, that environmental and geo-technical investigations do not reveal any conditions that would make the Option Lands unsuitable for its intended use;

(c) the Owner's representations and warranties shall be true and not misleading in any way and Trans Mountain shall not have become aware of any fact or thing which would reasonably lead it to believe otherwise; and

(d) the Owner shall have complied with Section 21.

27. If Trans Mountain does not give notice to the Owner that the conditions precedent described in Section 26 have been satisfied or are waived not later than fourteen (14) days prior to the Closing Date this Agreement shall terminate and be of no further force and effect.

Miscellaneous

28. The parties agree that the Consideration does not include GST of ________________ and that the Owner shall not collect GST from Trans Mountain in respect of the Consideration, and Trans Mountain shall file returns and remit GST to the Canada Revenue Agency in respect of the Consideration when and to the extent required by the *Excise Tax Act*.

29. The Owner agrees not to remove or allow the removal of any materials from the Option Lands (including any soil) while this Agreement remains in effect, or otherwise alter the Option Lands, or the use of the Option Lands, which may result in a material adverse impact on the Option Lands, or the use of the Option Lands by Trans Mountain.

30. The Owner shall execute all further deeds, documents and assurances, and shall do all such further things as may be reasonably required for the purpose of carrying out this Agreement according to its true meaning and intent.

31. This Agreement shall be binding upon and enure to the benefit of the heirs, executors, administrators, successors and assigns of the Owner and Trans Mountain, respectively.

32. If any provision contained in this Agreement or its application to any party hereto or circumstance shall, to any extent, be invalid or unenforceable, the remainder of this Agreement or the application of such provision to such parties or circumstances other than those to which it is held invalid or unenforceable shall not be affected.

33. Trans Mountain shall be responsible for:

    (a) all costs related to the subdivision of the Option Lands from the Property, if applicable; and

    (b) the costs of a legal survey of the Option Lands and the Section 114 Plan.

34. The Option Lands including all fixtures and other items to be purchased related to the Option Lands shall remain at the risk of the Owner until the Closing Date. In the event of loss, destruction or damage or any such property between the granting of the Option and the Closing Date, either such loss will be repaired and corrected at the expense of the Owner, except to the extent that such loss is directly due to the actions of Trans Mountain or its representatives, or such loss will be dealt with in an equitable manner by way of an adjustment of the Purchase Price. In the event the parties cannot agree on the adjustment it shall be settled by arbitration.

35. Trans Mountain shall have the right at any time and from time to time to assign all of its rights and obligations under this Agreement. The Owner shall not, in whole or in part, assign his interest in this Agreement without the prior written consent of Trans Mountain.

36. Time shall be of the essence. The provisions hereof shall survive the registration of all conveyances and shall not merge therein or therewith.

37. The Agreement shall be governed by and interpreted in accordance with the laws of the Province of British Columbia.

38. The Owner acknowledges receiving a Notice pursuant to Section 87 (1) of the *National Energy Board Act* concerning the above property.

IN WITNESS WHEREOF the parties hereto have duly executed this Agreement by their respective hands as of the day and year first above written.

Witness:	Owner:
Witness:	Owner:

TRANS MOUNTAIN PIPELINE L.P. by its General Partner TRANS MOUNTAIN PIPELINE ULC

Per:

Print name and position

Per:

Print name and position

SCHEDULE "A"

SCHEDULE "B"