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Will the Trans Mountain Pipeline and Tidewater Access Boost Prices and Save Canada's Oil Industry?

J. David Hughes

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Summary

ONE OF THE primary rationales for Kinder Morgan's Trans Mountain pipeline expansion project (TMEP), which will triple the capacity of the existing pipeline from Edmonton to Burnaby, BC, is to maximize the price for Alberta bitumen by getting oil from Alberta to "tidewater". Tidewater refers to ocean access in order to ship oil to overseas markets via tankers. Industry and the federal and Alberta governments argue that a pipeline to tidewater will unlock new markets (Asia in the case of the TMEP) where Canadian oil can command a better price than in the US, where the majority of Canadian oil is currently exported.

This paper examines the tidewater argument and other problematic assumptions that led to the pipeline's approval, including overly optimistic projections of future oil supply given the latest National Energy Board (NEB) projections and the Alberta government's cap on oil sands emissions, and the failure to consider alternative export pipelines given the federal government's and Trump Administration's approval of the Line 3 Restoration Project and the Keystone XL pipelines.

Non-existent Tidewater/Asia Price Premium

In its oil supply assumptions submitted to the NEB, Kinder Morgan claimed the TMEP would result in higher prices for Alberta bitumen, conveying a $73 billion windfall over 20 years to Canadian oil producers. Kinder Morgan's estimates were predicated in part on the assumption that a large differential will appear between the international price of oil (the "Brent" benchmark) and the North American price (the West Texas Intermediate [WTI] benchmark) over the first 20 years of the TMEP's life. This differential was estimated at between US$5 to US$8 per barrel from 2018–2038.

Historically, however, the differential between international and North American oil prices has been near zero or negative, and averaged just US$0.82 per barrel in 2016. Between 2011 and 2014 there was a significant international price premium caused by a pipeline bottleneck to the US Gulf Coast that drove down the North American price. The construction of new pipeline capacity has eliminated this bottleneck and the price differential is now near historical levels.

The US Gulf Coast represents the largest concentration of refineries in the world optimally designed to process heavy oil. Canadian oil sold on the US Gulf Coast fetches the same price as comparable heavy crudes (such as Mexican Maya), which sell at a discount to WTI due to their heavy gravity and high sulphur content, which makes them more costly to refine. The difference between Canadian heavy crude (Western Canada Select [WCS]) priced at Hardisty, Alberta, and Maya priced at Houston on the US Gulf Coast is solely due to the cost of transport from Hardisty to Houston, not an unfair discount.

Canadian heavy oil sold in Asia would actually command a *lower* price than in the US due to higher transportation costs (the TMEP pipeline tolls and costs of shipping by tanker). The additional discount for oil sold in Asia would be between US$2.06 and US$4.81 per barrel (depending on the US destination comparator).

Kinder Morgan maintained that Canadian oil is being forced into the finite North American market, which also does not stand up to scrutiny. The US relies on imports for 46 per cent of its crude oil requirements, and production from major heavy oil suppliers in Mexico and Venezuela is falling. The US market has the capacity to absorb significantly more Canadian oil, and even in the unlikely event that US markets were to become saturated, Canadian oil that reaches the Gulf Coast can be exported to world markets.

Problematic assumptions about oil supply, need for new pipeline capacity

In its submission to the NEB, Kinder Morgan exaggerated the need for new pipelines by overestimating future oil supply. The company's assumptions about future oil production, submitted to the NEB in September 2015 are considerably higher than NEB projections published in October 2016.

Furthermore, neither Kinder Morgan's nor NEB projections considered the supply constraints imposed by the Alberta government's cap on oil sands emissions introduced with its Climate Leadership Plan in November 2015. Considering both the most-recent NEB projections and the Alberta emissions cap, Kinder Morgan overestimated oil supply by 2.1 million barrels per day in 2038. Existing export pipeline and rail capacity are sufficient to move future production under Alberta's emissions cap, although rail would need to be used for incremental growth after 2019–2021.

Kinder Morgan's assumption in its NEB submission that no other export pipelines would be built is now obsolete because the federal government has approved Enbridge's Line 3 Restoration project (from Edmonton, Alberta, to Superior, Wisconsin), and TransCanada's Keystone XL pipeline (from Hardisty, Alberta, to Steele City, Nebraska). TransCanada recently received approval for Keystone XL from the Trump administration and it now seems likely that both of these pipelines will be built. These two pipelines would provide a 13 per cent surplus of pipeline-only export capacity *without* the TMEP.

Conflicting priorities

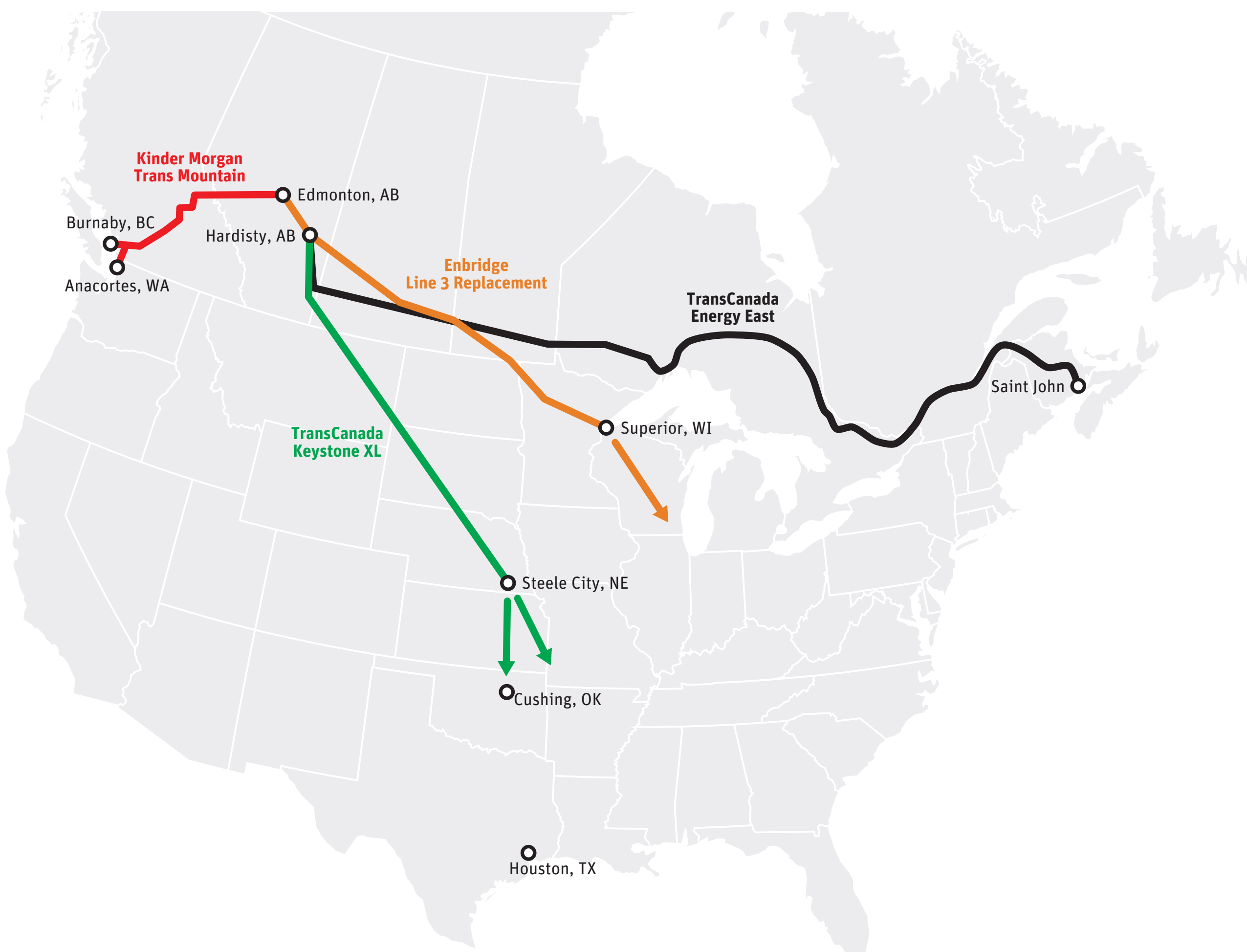
Increasing oil and gas production while at the same time trying to reduce carbon emissions are conflicting priorities. Expanding oil sands production by 53 per cent and emissions by 47 per cent above 2014 levels, as allowed under Alberta's Climate Leadership Plan, will require the rest of the Canadian economy to reduce emissions by 47 per cent by 2030 to meet Canada's Paris Agreement commitments. This will be virtually impossible in the time remaining barring an economic collapse.

Three new pipelines have been approved and a fourth (Energy East) is under review even though oil supply forecasts show that not all are needed. Of these, the TMEP is perhaps the worst choice because it must cross rugged, environmentally sensitive terrain, and would require greatly expanded tanker traffic into Vancouver's Lower Mainland, southern BC's most-populated area, and its ecologically vulnerable marine environment. The fact that the TMEP was approved by the NEB based on inflated oil supply and price assumptions, and without considering the other approved pipelines, should also have been a key consideration before federal approval was granted.

These conflicting priorities stem from the fact that Canada has no energy strategy beyond liquidating its remaining non-renewable resources as fast as possible to serve the economic interests of governments of the day. What we really need is a comprehensive energy strategy that addresses both the future energy security of Canadians and Canada's commitments on climate change.

PROPOSED OIL EXPORT PIPELINES

The Trans Mountain, Keystone XL and Line 3 pipelines have received federal government approval. Energy East is at the hearing stage.



1. Introduction

IN NOVEMBER 2016, the Trudeau government granted approval to the Trans Mountain expansion project (TMEP), a proposal to twin the existing 1,150-kilometre oil pipeline between Edmonton, Alberta, and Burnaby, BC and triple its capacity, to the dismay of many people concerned with the environmental impacts of increased tanker traffic and potential oil spills. A central justification for the approval was that the US was unfairly discounting Canadian oil and that Canada needed other customers to provide "a much better price for our product."[1] As well, Canada's export pipelines were at nearly full capacity and transporting oil by rail was deemed a more dangerous and costly option. New pipelines were needed, it was argued, as Alberta planned to significantly ramp up its oil sands production.

A review of the TMEP documentation provided by Kinder Morgan (KM, the project's proponent) to the National Energy Board (NEB), and of the political events since the NEB's authorization of the pipeline in May 2016, reveals that some of the assumptions that led to the pipeline's approval were questionable in the first place and others have been superseded by recent events. Key among these are:

- KM's assumed oil supply projection is much higher than the most recent NEB projection published in October 2016, and therefore exaggerates the need for new pipelines. Furthermore, neither KM's nor the NEB's projections incorporated the cap on oil sands emissions under Alberta's Climate Leadership Plan, which will further reduce future oil supply.

- KM's assumption that no other export pipelines would be built has been superseded. The Trudeau government approved the Line 3 Replacement Program, which will add 370 thousand barrels per day of capacity to an existing pipeline between Edmonton, Alberta, and Superior, Wisconsin, and the Trump administration (and Trudeau government) approved the Keystone XL pipeline project, which will carry 830 thousand barrels of crude oil per day from Hardisty, Alberta, to Steele City, Nebraska. Both of these pipelines now seem likely to be built, adding 1.2 million barrels per day of new export capacity without TMEP.

- KM's assumption that Canadian oil prices will increase significantly due to TMEP is predicated in part on the expectation that the North American oil price will be considerably lower than the international price between 2018 and 2038, despite the fact that this price differential has historically been near zero and averaged just $US0.82 per barrel in 2016. Furthermore, KM's price modelling projections assumed that US oil could not be exported, meaning that its free interchange on global markets would be restricted, which could reduce North American prices.[2] Subsequent legislation, however, has lifted the 40-year ban on US exports of crude oil.[3]

KM's assumptions on the economic benefits of TMEP are contained in two reports it submitted to the NEB as "replacement evidence" in September 2015: one, by Muse, Stancil and Co. (Muse Stancil),[4] projects price increases of Canadian crude oil and another, by the Conference Board of Canada,[5] projects other economic benefits. Recent developments that invalidate key assumptions in these reports on the need for and economic benefits from TMEP are reviewed below.

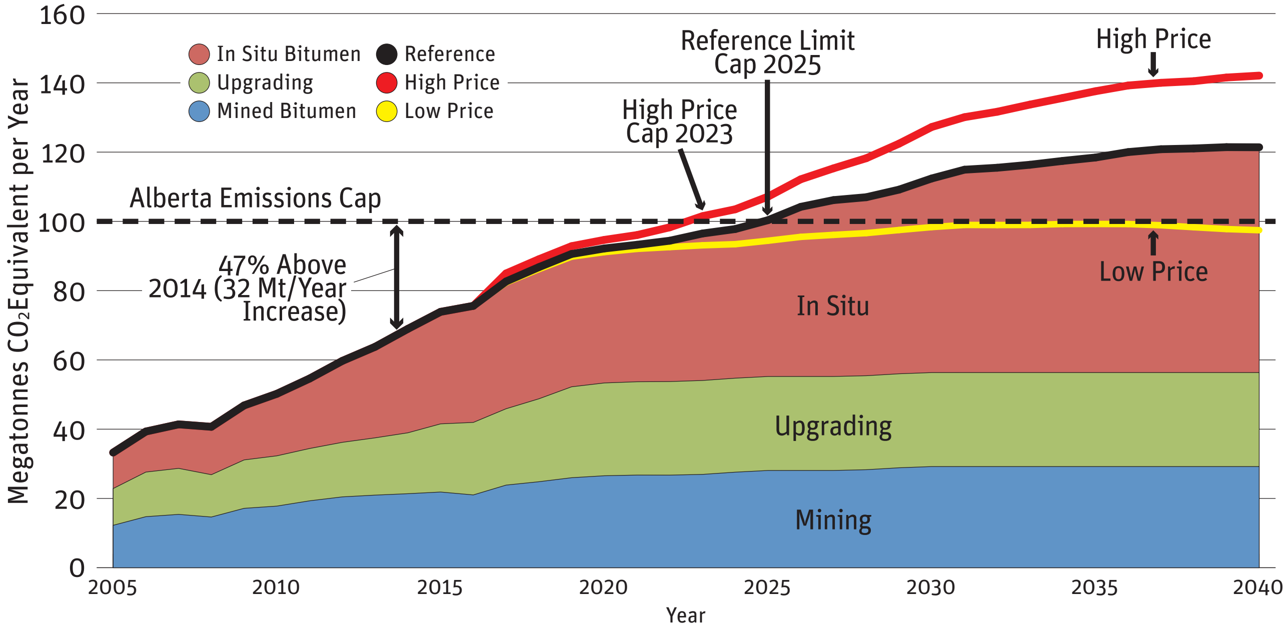
2. National Energy Board oil supply projections under the oil sands emissions cap

THE NEB PUBLISHED two reports on Canadian oil production that were not considered in its hearings on TMEP, both of which downgrade future oil supply. The latest of these, published in October 2016,[6] included "reference," "high price" and "low price" cases.[7]

Under its Climate Leadership Plan, the Alberta government has committed to capping all greenhouse gas (GHG) emissions from the oil sands at 100 megatonnes (Mt) per year.[8] In 2014, total emissions from the oil sands were 68 Mt, which means they will be allowed to grow by 32 Mt per year, or 47 per cent, from those levels. *Figure 1* illustrates the effect of this cap on oil sands emissions (see Appendix A for the methodology and sources used to calculate production under the emissions cap). The cap does not limit production until 2025 in the reference case, 2023 in the "high price" case, and in the "low price" case, production is not constrained as the cap is never reached.

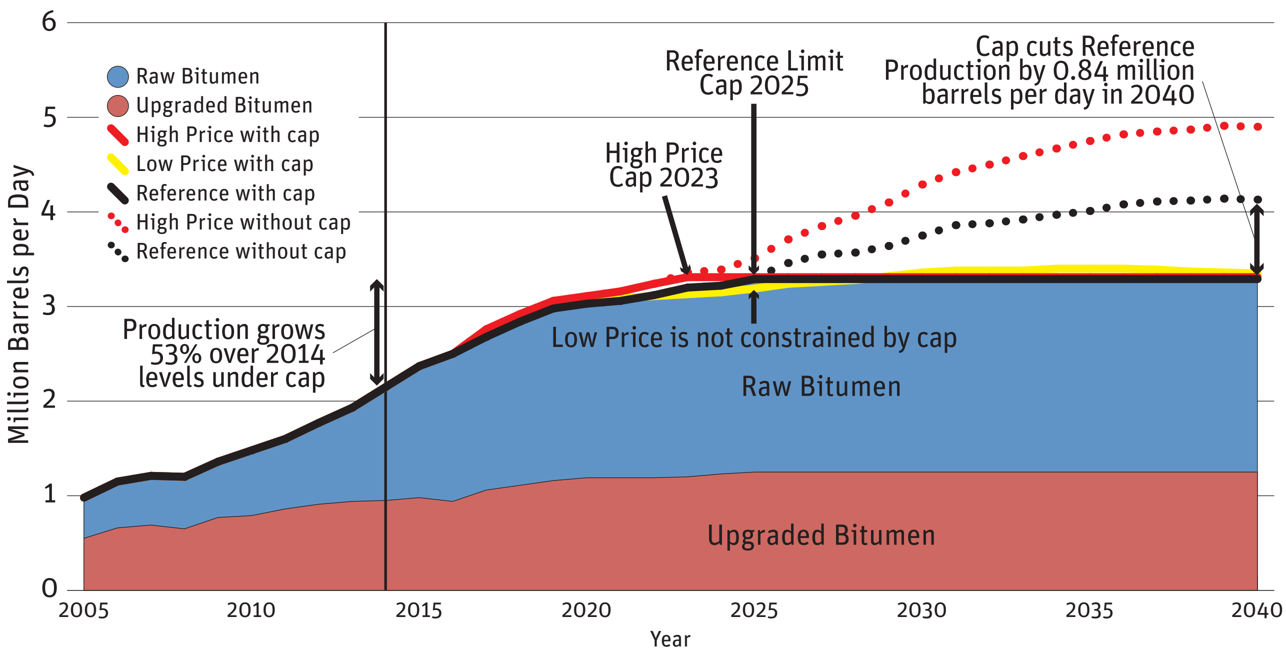
Figure 2 illustrates the effect of the cap on actual bitumen production. The cap allows bitumen production to grow by 53 per cent over 2014 levels in the reference case, which reaches the cap in 2025 (production can grow

FIGURE 1 Total emissions in the NEB's reference case through 2040, by extraction method and upgrading



Source Data from National Energy Board, *Canada's Energy Future 2016: Update — Energy Supply and Demand Projections to 2040.* Also shown are the Alberta government's 100 Mt per year emissions cap and the NEB's "high price" and "low price" cases.

FIGURE 2 Marketable bitumen production in the NEB production scenarios through 2040, with and without Alberta's 100 Mt/year emissions cap



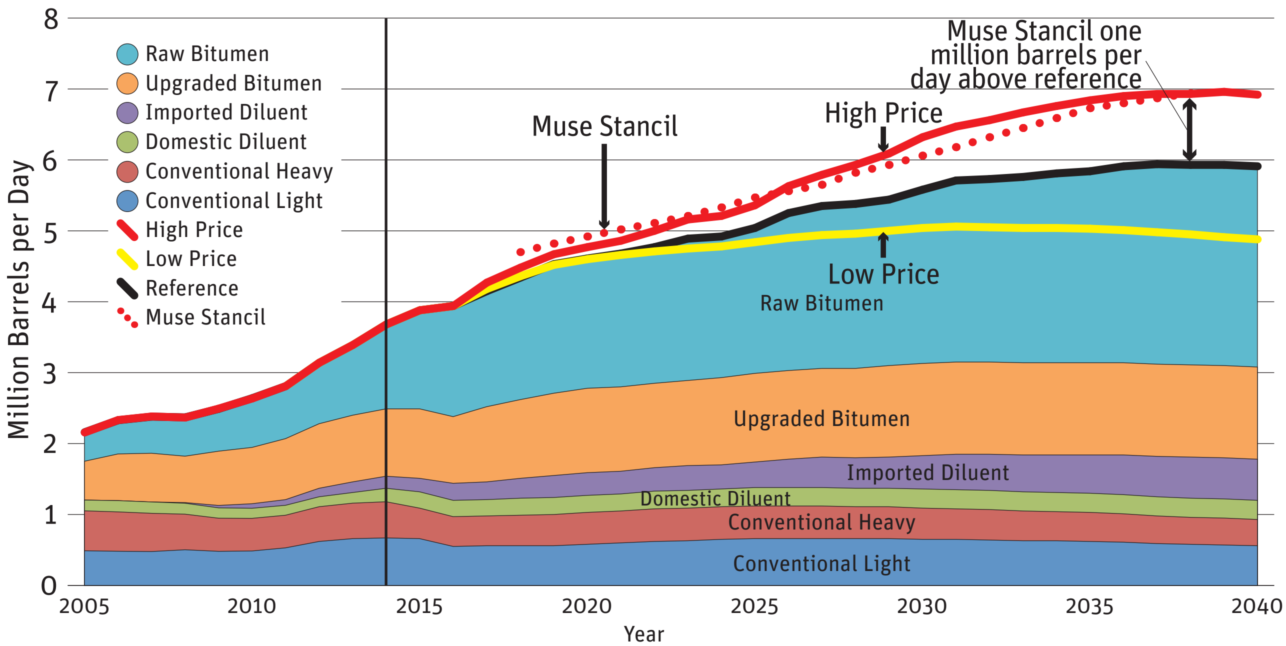
Source Data from National Energy Board, *Canada's Energy Future 2016: Update — Energy Supply and Demand Projections to 2040.* Raw bitumen is converted into upgraded bitumen with a volume loss of 14 per cent, so the volumes here reflect delivered quantities. Production in the reference case can grow 53 per cent over 2014 levels before being limited by the emissions cap.

more than emissions, as most of the increased production is sold as raw bitumen and not upgraded to synthetic oil, and therefore eliminates that source of emissions). The "high price" case hits the cap in 2023 and the "low price" case never reaches the cap. In the "reference" case, the emissions cap curtails bitumen production in 2040 by 840,000 barrels per day.

The total supply from Western Canada used in domestic refineries and requiring export pipelines includes conventional light and heavy oil, and upgraded and raw bitumen. It also includes diluent required for blending with the raw bitumen to allow it to flow through pipelines. Raw bitumen requires a 30 per cent blend of light hydrocarbons, usually condensate, to create "dilbit," or a 50 per cent blend of synthetic crude oil to create "synbit." Canada does not produce enough diluent domestically, which means that the additional amounts needed for increased bitumen production must be imported.

Total Western Canadian oil supply based on the latest NEB forecasts is illustrated in *Figure 3*. Also shown is the growth in supply assumed by KM in its report for the TMEP hearings. Even without Alberta's emissions cap,

FIGURE 3 Western Canadian oil supply in the NEB's reference case through 2040

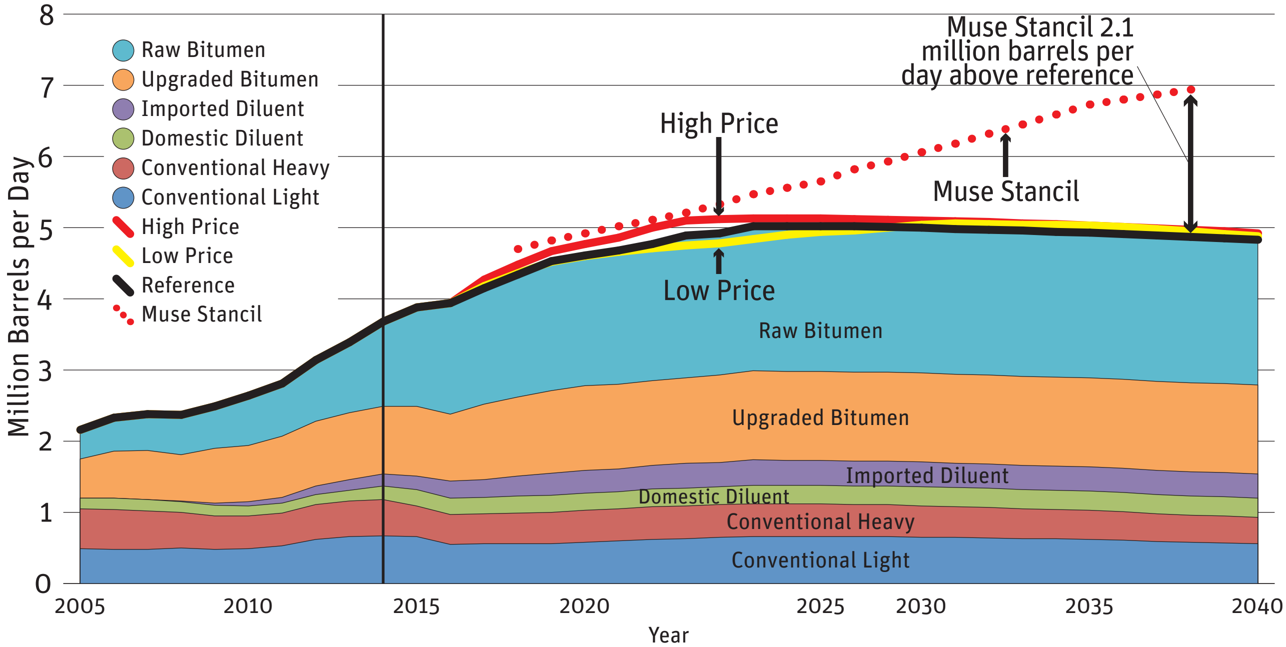


Source Data from National Energy Board, *Canada's Energy Future 2016: Update — Energy Supply and Demand Projections to 2040*. Also shown are the NEB's "high price" and "low price" scenarios under the cap and KM's (Muse Stancil) assumption.

KM overestimates supply by one million barrels per day compared to the NEB's reference case in 2038.

Figure 4 illustrates Western Canadian supply under the Alberta emissions cap with the latest NEB forecasts. KM's assumption overestimates supply by 2.1 million barrels per day compared to the NEB reference case in 2038. Such a large discrepancy in this critical input assumption invalidates the "Western Canadian crude oil producer's benefits" that KM provided to the NEB's TMEP hearings.

FIGURE 4 Western Canadian oil supply in the NEB's reference case through 2040, with the Alberta government's oil sands emissions cap



Source Data from National Energy Board, *Canada's Energy Future 2016: Update — Energy Supply and Demand Projections to 2040.* Also shown are the NEB's "high price" and "low price" assumptions under the cap as well as KM's (Muse Stancil) assumption.

3. Existing and proposed pipeline and rail export capacity

EXISTING EXPORT CAPACITY from Western Canada includes several pipelines as well as extensive rail-loading facilities. Shippers prefer to use pipelines to transport diluted bitumen (dilbit) due to their lower cost, and therefore new pipeline capacity would replace rail for incremental production that would otherwise have to be shipped by rail.

Table 1 illustrates the capacity, in thousands of barrels (or kilobarrels) per day (kbd), of existing export pipelines and railways as well as proposed pipelines, including the Line 3 and Keystone XL projects, both of which are likely to be built given their approval by the Trudeau government and Trump administration.

Existing export pipeline capacity is similar to KM's assumptions (3,974 kbd at 95 per cent availability versus 3,961 kbd).[12] *Figure 5* illustrates Western Canadian supply compared to existing export pipeline and rail capacity and domestic refinery consumption.

Although the existing pipelines will reach full capacity between 2019 and 2021, depending on which NEB oil sands expansion scenario is considered, by including existing rail loading-facilities there is sufficient capacity to handle all scenarios under the Alberta emissions cap through 2040 without building new pipelines. However, moving dilbit by rail is double the cost of moving

TABLE 1 Existing pipeline and rail export capacity and refinery consumption in Western Canada along with proposed pipelines

Export capacity from Western Canada (kbd)

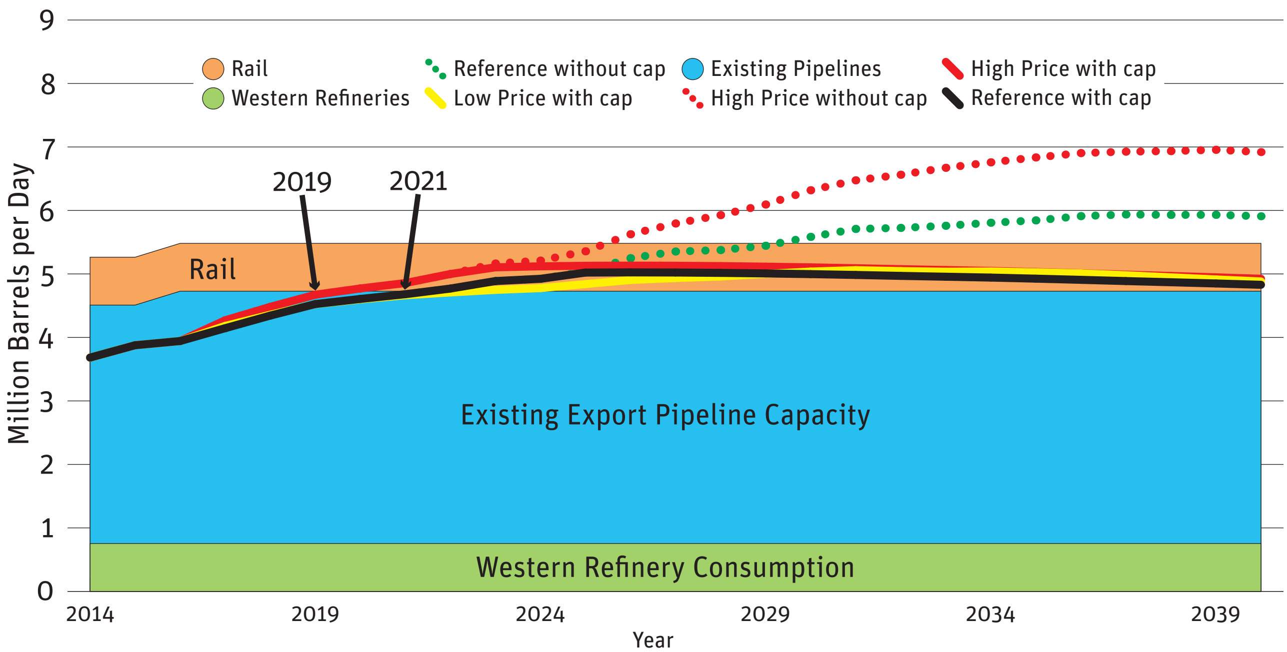
Pipeline	Nameplate capacity	Net capacity at 95%	Source
Existing pipelines			
Enbridge Mainline	2,851	2,708	CAPP 2016
KM Trans Mountain*	300	235	CAPP 2016
Spectra Express	280	266	CAPP 2016
TransCanada Keystone	591	561	CAPP 2016
Rangeland–Milk River	214	203	AE 2009
Total existing capacity	4,236	3,974	
Western refinery receipts and rail capacity			
Refinery consumption[9]	671	671	CAPP 2016
Rail export capacity	754	754	CAPP 2016
Grand total	5,661	5,399	
Proposed pipelines likely to be built under the Trump administration			
Line 3 replacement	370	352	CAPP 2016
TransCanada Keystone XL	830	789	CAPP 2016
Existing plus likely capacity	6,861	6,539	
Proposed Canadian "tidewater" pipelines[10]			
KM Trans Mountain expansion	590	561	CAPP 2016
TransCanada Energy East	1,100	1,045	CAPP 2016
Total	8,551	8,145	

Source Data from the Canadian Association of Petroleum Producers, *2016 CAPP Crude Oil Forecast, Markets & Transportation* (CAPP 2016) and Alberta Energy, *BRIK Infrastructure and Bitumen Supply Availability,* 2009 (AE 2009). Net capacity discounts nameplate capacity by 5 per cent allowing for maintenance and outages.[11]
* Chevron's Burnaby refinery consumption is subtracted from the existing Trans Mountain pipeline export capacity as it is consumed domestically and is therefore not available for export.

it by pipeline. Furthermore, as dilbit flows readily, it is an environmental hazard in the event of an accident. Moving raw bitumen by rail may therefore be safer and more cost effective but it has yet to be attempted at scale.

Donald Trump's election in the US has changed the political landscape for pipelines. Whereas in late 2015 the Obama administration cancelled the Keystone XL pipeline, which would carry 830,000 barrels of crude oil per day from Hardisty, Alberta, to Steele City, Nebraska, President Trump has reversed this decision. The Trudeau government has also long supported it.[13] TransCanada resubmitted its application for the project and received

FIGURE 5 Western Canada supply with and without the Alberta emissions cap compared to existing pipeline and rail export capacity and Western Canadian refinery consumption



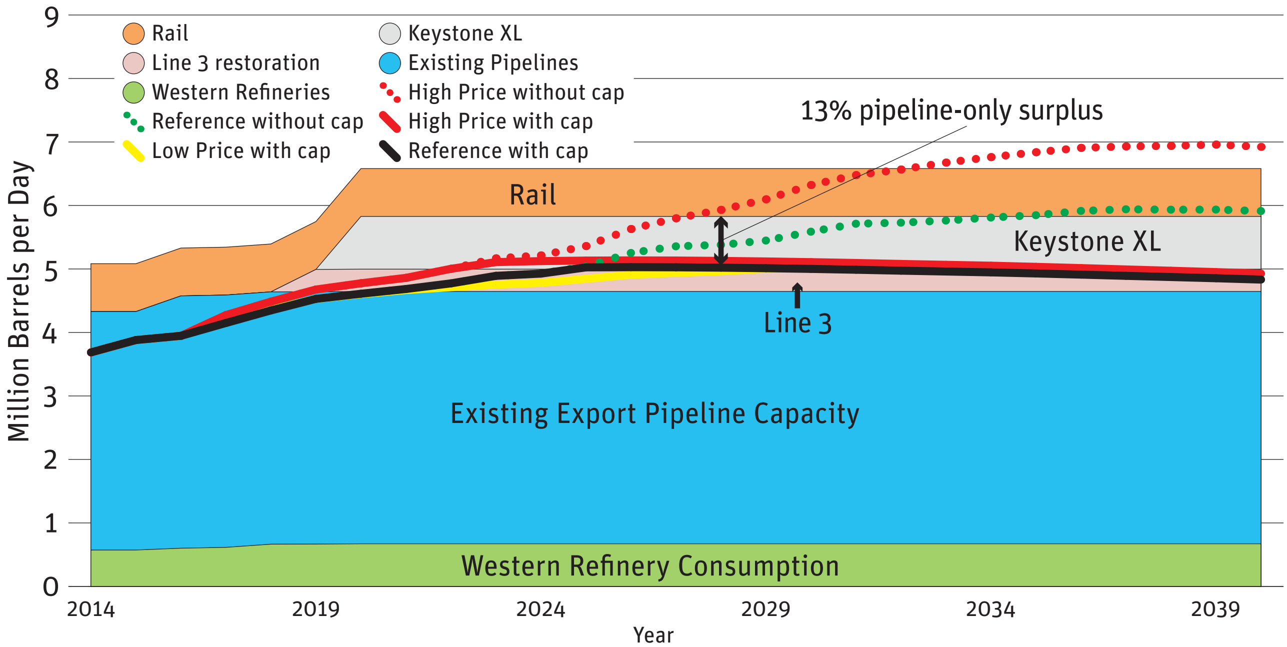
Source Data from National Energy Board, *Canada's Energy Future 2016: Update—Energy Supply and Demand Projections to 2040.* The latest "reference," "high price" and "low price" NEB forecasts of supply are shown.

presidential approval shortly thereafter.[14] The Trump administration will also likely expedite the completion on the US side of the border of the Line 3 project, which the Trudeau government recently approved. This pipeline would add a further 370,000 barrels per day of export capacity.

Building these two pipelines would add 1.2 million barrels per day of pipeline export capacity. Unlike TMEP, these projects do not cross mountainous terrain with its higher environmental sensitivity, nor do they rely on tankers to move the oil. Notwithstanding the political rhetoric about a price "premium" for Canadian oil in Asia, Hal Kvisle, the former CEO of TransCanada Corporation and Talisman Energy, pointed out "the highest value market we can move our heavy crude oil to is Houston...there is no refining centre in the world that is better—that has more of the right equipment—to process that kind of crude oil than that enormous refining centre."[15] (This fact is discussed in more detail in the following section.)

Figure 6 illustrates pipeline and rail capacity compared to Western Canadian oil supply if the Line 3 project and Keystone XL are built. Under Alberta's emissions cap, a 13 per cent surplus of pipeline-only export capacity

FIGURE 6 Western Canada supply with and without the Alberta emissions cap compared to existing export pipeline, rail and refining capacity if the Line 3 project and Keystone XL pipelines are built



Source Data from Canadian Association of Petroleum Producers, *2016 CAPP Crude Oil Forecast, Markets & Transportation* and National Energy Board, *Canada's Energy Future 2016: Update — Energy Supply and Demand Projections to 2040.* Pipelines are assumed to run at 95 per cent of nameplate capacity.

would exist when production peaks in 2026 (see Appendix B). If rail export capacity is added, surplus capacity would be 23 per cent.

4. "Tidewater" price premium: Myth or reality?

KM'S SUBMISSION TO the NEB (the Muse report) estimated a return to Canadian oil producers of $73 billion through an increase in oil prices if TMEP goes ahead. Based on this submission, the Conference Board revised and resubmitted its earlier report to include only its scenario of maximum economic benefits from TMEP.

However, in its approval document for TMEP, the NEB stated: "Muse said that oil is a global commodity with a well-established transportation infrastructure and, as a result, global benchmark prices are usually identical once adjustments for quality and transportation costs are taken into account."[16]

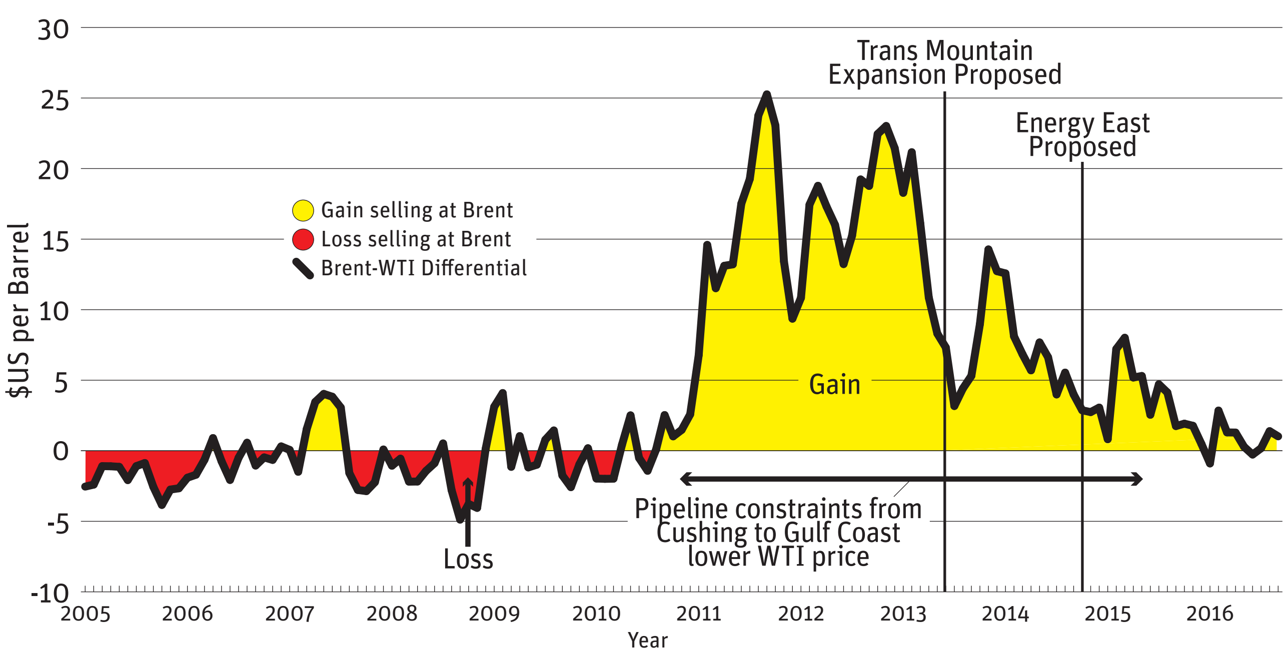
Although the NEB incorrectly attributed this statement to Muse (it was the first sentence in the Conference Board report[17]), it is a fundamental truth of oil markets. The NEB went on to say: "Muse said that this has not been the case in recent years with North American benchmark prices lagging considerably behind their global peers... Muse said that projects such as the Trans Mountain Expansion Project offer Canadian crude oil producers precisely the diversification lacking in 2012–2013."

Muse was referring to the price differential that existed between the international price of oil — the Brent benchmark — and the North American price — the West Texas Intermediate (WTI) benchmark — in 2012 and 2013.

Muse failed to mention that this differential no longer exists.[18] The differential was a result of the rapid rise of shale oil production in the US and a lack of pipeline capacity to move it between Cushing, Oklahoma (where the WTI benchmark is set), and the US Gulf Coast (where international prices may be accessed). Construction of new pipelines has since reduced this differential to its historical levels of near or below zero (given that WTI is a slightly better grade of oil than Brent). *Figure 7* illustrates the Brent-WTI differential between 2005 and 2016. The 2012–2013 period, on which Muse based its comments and on which the NEB relied in making its decision about TMEP, is clearly an anomaly and is unlikely to be repeated.

Canadian heavy oil, represented on the stock market by the Western Canadian Select (WCS) benchmark priced at Hardisty, Alberta, compares in quality to the Maya benchmark (a Mexican heavy oil), which is sold at "tidewater" in the Gulf of Mexico. Both of these crude oils are discounted due to their heavy, sour nature (low API gravity and high sulphur content) which makes them more costly to refine than light, sweet oil (high API gravity and low sulphur content). The difference in price between Maya at Houston and WCS at Hardisty is the pipeline toll from Hardisty to Houston.

FIGURE 7 Brent and WTI price differential showing "loss" or "gain" from accessing international markets, 2005 to 2016



Source WTI and Brent prices from World Bank via IndexMundi, accessed December 9, 2016. The differential averaged $US0.82 in 2016.[19]

Table 2 summarizes the quality discount and pipeline tolls for Maya and WCS. The quality discount between Maya at the US Gulf Coast and the international Brent price is comparable to the quality discount between WCS and WTI at Houston.[20] The average discount of WCS at Hardisty from WTI over 2015 and 2016 was US$13.52 per barrel (an average of 2015 and the first ten months of 2016, *Table 2*), which is a quality discount (US$8.12—using the Brent-Maya price as a proxy for what WCS would fetch on the US Gulf Coast) and the pipeline toll (US$5.40). A snapshot of Houston prices on September 23, 2016 (*Table 2*), shows that the quality discount on that day for WCS from WTI at Houston was US$9.04 and the toll from Hardisty to Houston was US$5.68 for a total differential between WCS at Hardisty and WTI at Houston of US$14.72 per barrel. (As of April 27, 2017, the differential between WCS at Hardisty and Lousiana Light Sweet—LLS, a comparable crude oil grade to WTI—at Houston stood at just US$11.40 per barrel according to RBN Energy.)

Thus, there is no evidence to support Alberta Premier Notley's claim: "We are selling our product at a very discounted rate into a market that is continuing to be our greatest competitor."[23]

WCS commands the same quality discount as Maya, which has access to tidewater. The further discount of WCS at Hardisty compared to Houston is a result of the transportation cost to Houston, not of an unfair penalty imposed by the US as alleged by Premier Notley and federal politicians. The

TABLE 2 Discounts for quality and pipeline tolls for WCS and Maya to the US Gulf Coast

Monthly price average, 2015–2016

$US/bbl	2015	2016
WTI	$48.75	$41.24
Brent	$52.40	$42.04
WTI-WCS	$13.47	$13.60
Brent-Maya at Houston (heavy discount)	$8.38	$7.77
Toll Hardisty to Houston	$5.09	$5.82

Snapshot on September 23, 2016

WTI Houston -WCS Houston (heavy discount)	$9.04
Toll Hardisty to Houston	$5.68
WTI Houston -WCS Hardisty	$14.72

Source Data from Baytex Energy. 2016 is an average of the first 10 months.[21] Also shown is a snapshot on September 23, 2016, of the WCS quality discount from WTI at Houston and the Hardisty to Houston toll.[22]

US is the largest oil importer in the world and imported 46 per cent of its crude oil requirements in 2016.[24] Production from Venezuela and Mexico, two major suppliers of heavy oil to the US, is declining (Venezuela is down 30 per cent from 1997; Mexico is down 34 per cent from 2004),[25] leaving a growing market for Canadian oil at world prices. The US also has the largest refinery complex in the world that is designed to optimally handle heavy oil such as Canadian crude.

Other uncertainties that invalidate KM's assertion of a $73 billion benefit to Canadian producers due to TMEP are reviewed in Appendix C. Key among these are the assumption of far higher production than is likely given the announced emissions cap and the assumption that no other pipelines will be built, both of which invalidate the benefit assertion.

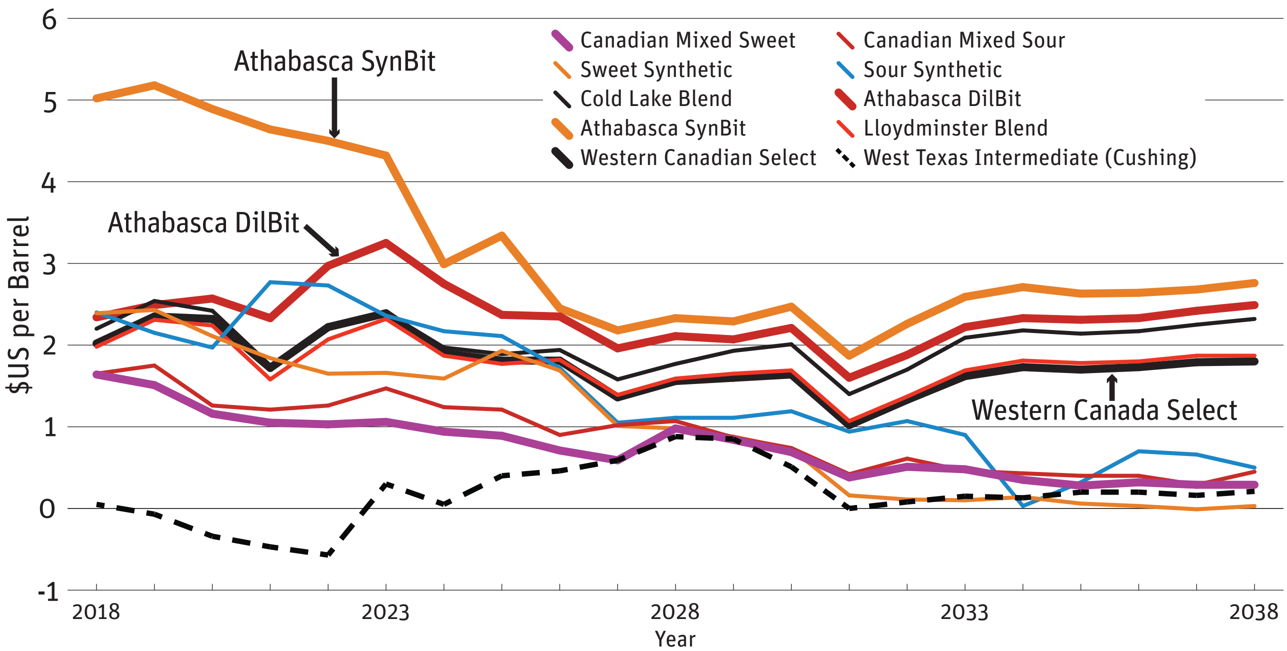
5. Asia price premium

GIVEN THAT GOVERNMENT and industry use the so-called Asia price premium as one of their key selling points for TMEP, further analysis is warranted to ascertain whether or not it exists and to examine the assumptions that led KM to allege vast netbacks to Canadian producers as a result of twinning this pipeline.

Unlike the Conference Board, which pointed out that “global benchmark prices are usually nearly identical to one another once adjustments for quality and transportation costs are taken into account,” KM’s consultant (Muse) asserted, “It is a fundamental economic principle that reducing the supply of a commodity, all else equal, will increase its price.” On this basis, the Muse Crude Oil Market Optimization Model determined that Canadian producers could see a price increase of up to US$5.18 per barrel, as illustrated in *Figure 8*, by removing 500 kbd from North America via TMEP. The two crude blends with biggest anticipated gains — Athabasca DilBit and Athabasca SynBit — are the main heavy blends exported to northeast Asia in the Muse model. Muse even estimates a slight impact on the WTI benchmark at Cushing. Based on these projections, Muse calculated a $73 billion undiscounted benefit to Canadian oil producers between 2018 and 2038 from building TMEP. (Using a 10 per cent discount rate shrinks this benefit to $22 billion.)

A key assumption is that the differential between North American (WTI) and international (Brent) prices will develop between North American (WTI) and international (Brent) prices at the time TMEP is commissioned. *Figure 9* illustrates the Muse assumption compared to the NEB’s latest forecast and

FIGURE 8 Price benefit for Canadian oil producers as a result of building TMEP, 2018 to 2038, as calculated by Muse Stancil

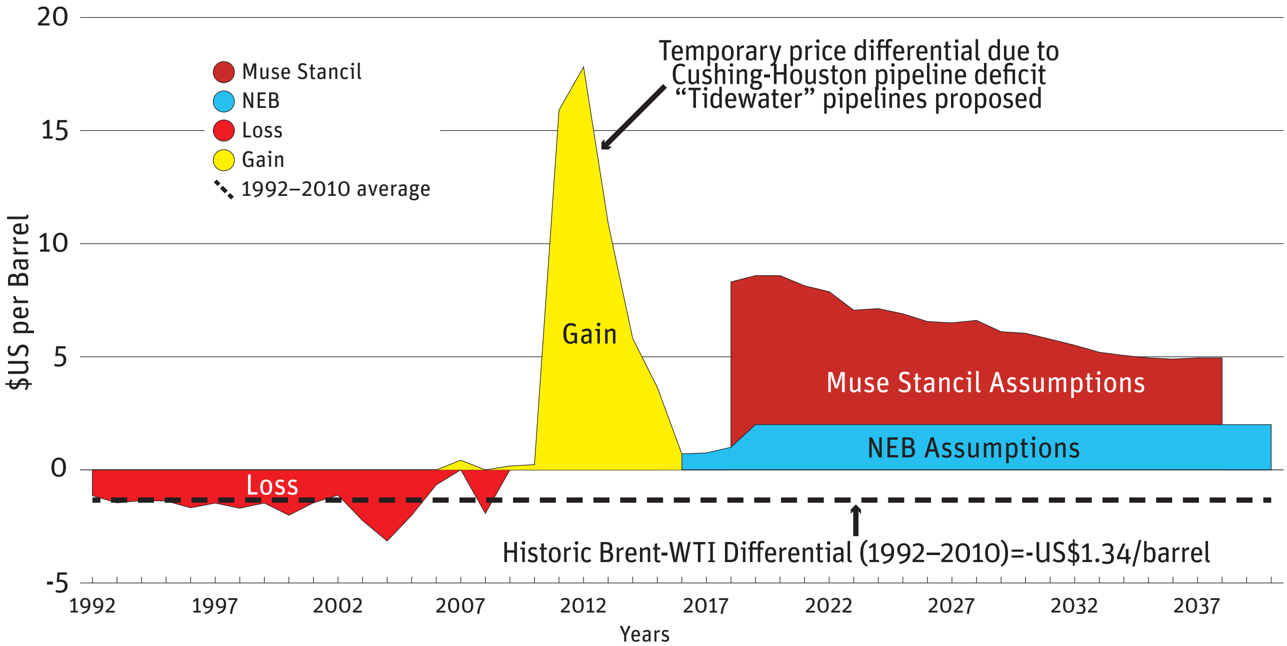


Source Data from Muse Stancil, *Market Prospects and Benefits Analysis of the Trans Mountain Expansion Project for Trans Mountain Pipeline (ULC)*, September 2015.[26]

the historical Brent-WTI price differential. Muse assumes a price differential of over eight dollars per barrel in early years tapering to five dollars per barrel in later years, whereas the NEB assumes an average price differential of two dollars per barrel. As noted earlier, the large differential that existed between 2011 and 2014 was a one-time event caused by a pipeline bottleneck at Cushing. It is therefore unreasonable to project such a high penalty over a 20-year period. If anything, the differential is likely to remain at par or drop to its historical minus US$1.34 per barrel, which would create a loss for every barrel exported to Asia even without considering the higher transportation costs to get it there.

Figure 10 illustrates KM's prediction as to how the destination for oil will change between 2018 and 2038 due to TMEP. At present, the principal markets for Canadian heavy oil are in the US Midwest and the Gulf Coast. The existing Trans Mountain pipeline provides mainly light oil to Chevron's Burnaby refinery, refineries in Washington State and to a lesser extent California. TMEP would, for the most part, divert shipments from the US Gulf Coast to Northeast Asia while other markets would remain largely the same (most changes to other markets are in light oil, not heavy). Exports to the

FIGURE 9 Historical and projected differential between North American (WTI) and international (Brent) prices, 1992 to 2040



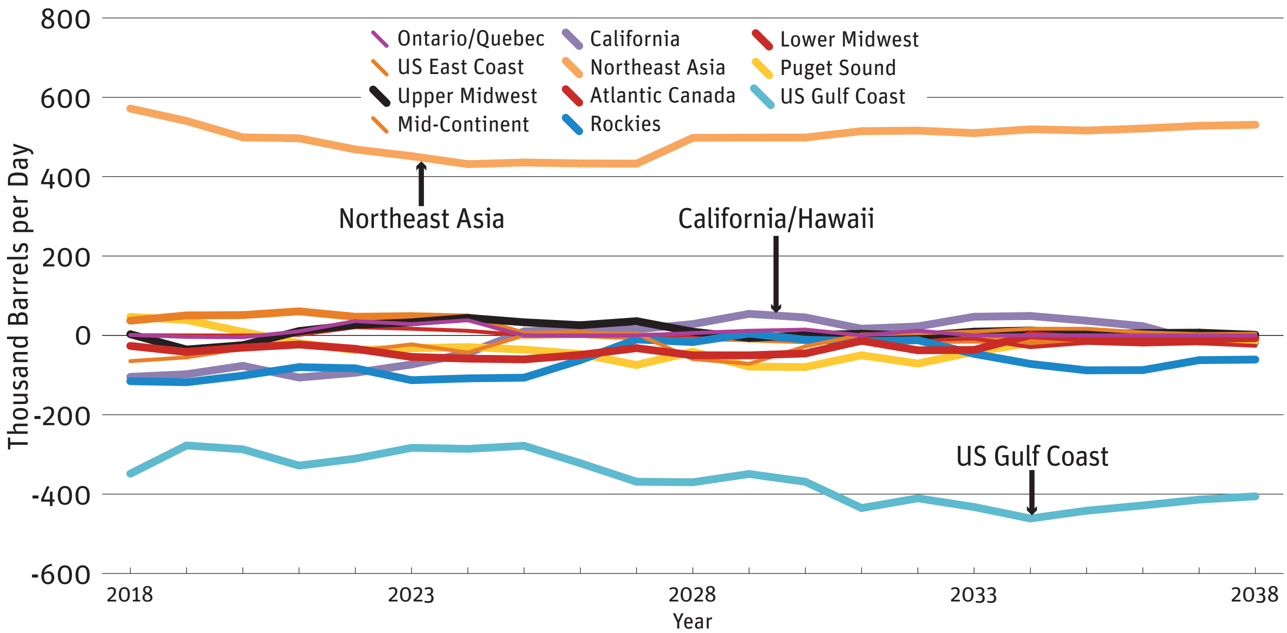
Source Data from US Energy Information Administration via IndexMundi; Muse Stancil, *Market Prospects and Benefits Analysis of the Trans Mountain Expansion Project for Trans Mountain Pipeline (ULC)*, September 2015; National Energy Board, *Canada's Energy Future 2016: Update—Energy Supply and Demand Projections to 2040*. When Brent prices are higher than North American prices there is a gain from accessing international markets, when they are lower there is a loss. Future projections of the price differential from the Muse report[27] and the NEB forecast[28] are also shown.

Puget Sound (Washington State) and California markets would be reduced in early years and increased in later years.

Muse asserts that "TMEP enables the Canadian crude oil producers to access the higher priced Pacific Basin markets." But Muse's price assumptions for Maya, as a proxy for Canadian heavy oil, show just US$0.17 per barrel more in Singapore than on the US Gulf Coast between 2010 and 2025, and average just US$0.08 cents per barrel between 2016 and 2025.[30] Furthermore, for its January 2017 deliveries, Petróleos Mexicanos (PEMEX), the company that markets Mexican Maya crude, maintained a US$5.95 per barrel discount for oil moving to Asia compared to the US Gulf Coast, and a $2.25 discount for oil moving to Europe.[31] This discount allows for transportation costs so that the crude is competitive in Asian and European markets.

When queried about the so-called Asian price premium by the Tsawout First Nation, KM stated: "An 'Asian Premium price differential' is not used in the analysis and is nowhere discussed in the Muse Report."[32] So, KM did not in fact assert that an Asian price premium exists. This fact, in conjunc-

FIGURE 10 Change in destination for light and heavy oil as a result of building TMEP, 2018 to 2038, as calculated by Muse Stancil

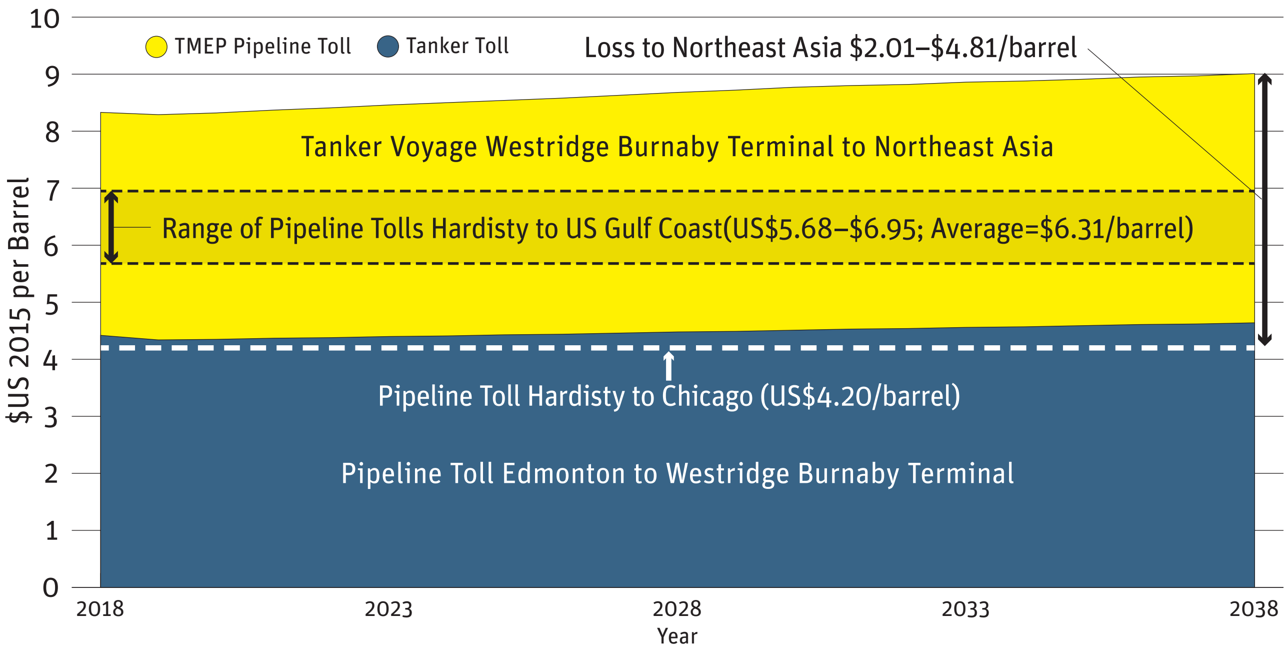


Source Data from Muse Stancil, *Market Prospects and Benefits Analysis of the Trans Mountain Expansion Project for Trans Mountain Pipeline (ULC)*, September 2015.[29]

tion with actual price data outlined above, makes statements alleging a price premium for tidewater access by Premier Notley and other politicians highly suspect.

Given that the quality discount for heavy oil is essentially the same in Asia as on the US Gulf Coast, the amount of lost revenue from transporting oil to Asia compared to the Gulf Coast and Midwest markets can be calculated using the toll assumptions for TMEP and the tanker voyage in the Muse report. *Figure 11* summarizes the transportation tolls for shipments to Asia compared to shipments to US markets. The pipeline plus tanker toll to northeast Asia is over US$8.00 per barrel, whereas the toll from Hardisty to the US Gulf Coast is between US$5.68 and US$6.95 for committed shipments (higher for spot shipments — see *Figure 11* for references),[33] and the toll from Hardisty to Midwest refineries in the Chicago area is US$4.20 per barrel. The increase in the transportation cost to Asia compared to US markets would amount to a loss — based on transportation cost alone — of between US$2.01 and $4.81 per barrel over the first 20 years of TMEP (assuming an average US Gulf Coast toll of US$6.31 per barrel; loss is $2.01-$4.13 in 2018 rising to $2.69-$4.81 in 2038).

FIGURE 11 Cost of transporting oil via TMEP and tanker to Asia compared to the cost of pipeline tolls to the US Gulf Coast and the US Midwest, 2018 to 2038, as calculated by Muse Stancil and Natural Resources Canada



Source Data from Muse Stancil, *Market Prospects and Benefits Analysis of the Trans Mountain Expansion Project for Trans Mountain Pipeline (ULC)*, September 2015.[34] The toll from Hardisty to Chicago is calculated from Natural Resources Canada data35 and the higher toll from Hardisty to the Gulf Coast is from the Canadian Association of Petroleum Producers.[36]

KM maintains that Canadian oil is "being forced into the finite North American market," but this statement does not stand up to scrutiny. The US is the largest oil importer in the world, relying on imports for 46 per cent of its crude oil requirements. It is also a significant and growing exporter of petroleum products but needs crude oil imports to produce them. Canadian oil constituted 41 per cent of US imports in late 2016 and is increasingly offsetting imports from Mexico and Venezuela (where production is declining), the Middle East and elsewhere. Oil production in the US is also down since its peak in 2015.

The US market has the capacity to absorb significantly more Canadian oil, and even in the unlikely event that US markets were to become saturated, Canadian oil that reaches the Gulf Coast can be exported to world markets.

Notwithstanding the above facts, the Alberta government filed a final argument[37] with the NEB on TMEP in January 2016, which included the following statements:

- “Because of limited market access, western Canada’s oil price has persistently been undervalued relative to world prices.”
- “The Project would significantly increase access to premium Northeast Asian markets, resulting in higher prices for both Western Canadian heavy and light crude oil.”
- “Without developing additional tidewater pipeline capacity, Canada’s Western Canadian crude oil resources and Canada’s governments will not realize the appropriate benefits that other producing nations receive. Alberta submits that the loss from price discounting is of such size and persistence that it cannot be in the Canadian public interest.”
- “By any reasonable account, Western Canadian heavy crude oil production is forecast to significantly increase [referencing the Muse forecast that doesn’t include the Alberta oil sands emissions cap and overestimates 2038 supply by 2.1 million barrels per day]. The Government of Alberta agrees with these forecasts, and submits that the Western Canadian oil sands are expected to experience healthy growth.”
- “Increased tidewater access for energy resources would enable Canadians to receive fair value for the resources they own and continue to sustainably develop in the best interest of all Canadians.”

6. Conclusions and implications

THE ENTHUSIASM FOR tidewater pipelines arose out of the large differential that existed between the international (Brent) and North American (WTI) price of oil from 2011 to 2014. During this time, the US rapidly grew production of tight oil (light crude oil found in shale and other low permeability rocks) and a lack of pipeline capacity created a bottleneck moving it from the central hub in Cushing, Oklahoma, where the WTI benchmark is set, to tidewater on the US Gulf Coast, where international prices can be accessed. This bottleneck has been eliminated with the construction of the southern leg of the Keystone XL pipeline and the development of the Seaway Crude Pipeline System. As a result, the price differential has retreated from a high of over US$20 per barrel in 2012 to an average of US$0.82 in 2016. Historically, the Brent price has been lower than WTI, trading at an average discount of US$1.34 per barrel from 1992 to 2010.

The Muse report's assessment that Canadian oil producers will gain $73 billion in benefits from an increase in oil prices due to TMEP is overstated. In fact, TMEP's effect on prices may actually be negative because the report is based on flawed assumptions and because major new developments have taken place since it was submitted to the NEB. These include the facts that:

- Muse vastly overestimated Western Canadian oil supply which, under the Alberta government's oil sands emissions cap, will be 2.1 million barrels per day lower in 2038 than Muse assumed.
- Muse did not consider additional export pipelines such as Keystone XL and the Line 3 expansion, both of which now seem likely to be built under the Trump administration.
- The transportation bottleneck that caused the differential between international and North American prices from 2011 through 2014 and led to enthusiasm for pipelines with tidewater access has nearly been eliminated. Muse assumed that this differential would reappear and remain between five and eight dollars per barrel for the first 20 years of TMEP's life, but this scenario is highly unlikely given the historical price relationship and the incentive for US oil producers to keep this differential at a minimum.

Given these facts, Muse's estimate of $73 billion of increased revenues to oil producers because of TMEP likely won't materialize. Jobs would certainly be created during the construction phase, but as economist Marc Lee pointed out based on KM filings, British Columbia would gain just 50 permanent long-term jobs and only 90 positions would be created overall.[38] No additional employment would occur in the oil sands, as the Muse model assumed production would be the same, with or without TMEP. Lee also pointed out that the economic benefits purported for TMEP by the Conference Board do not consider the potential costs of tanker spills and other ecological impacts on the south coast of BC.

The Asia price premium touted by the Alberta and federal governments does not exist, and Muse avoided any reference to such a premium in its report. The price data in the Muse report show that heavy oil prices in Asia are essentially the same as in North America. However, the tolls to move oil from Alberta to northeast Asia are higher than to move it to markets in the US Midwest and the Gulf Coast, resulting in a loss of $2 to $4.80 per barrel on exports to Asia. Economist Jeff Rubin suggests these losses may be higher,[39] given that refineries on the US Gulf Coast and in the Midwest represent the largest concentration of refineries in the world able to optimally refine heavy oil into its highest-value products.

Although sufficient pipeline and rail capacity exists to handle oil sands production under the Alberta emissions cap, after 2019–2021 any incremental growth in production would require the oil to be moved by rail. Currently less than 2 per cent of the Western Canadian oil supply travels by rail. The Line 3 expansion and Keystone XL pipeline, both of which are supported by the Trudeau government and the Trump administration, would add 1.2 million barrels per day of export capacity (more than double TMEP) and are likely to be built. These two pipelines alone would create a 13 per cent surplus of pipeline-only export capacity under Alberta's emissions cap, eliminating any need for TMEP and its associated higher level of environmental risk.

The Alberta government touts its oil sands emissions cap, which allows greenhouse gas emissions to grow by 47 per cent and production to grow by 53 per cent above 2014 levels, as a way to reduce emissions and allow Canada to meet the climate change commitments it has agreed to under the Paris Agreement. Increasing oil sands emissions by this amount, while still meeting the Paris Agreement reduction targets, will require the rest of Canada's economy to reduce emissions by 47 per cent by 2030, which is a very difficult challenge.[40] Limiting the growth of oil sands emissions to less than the increase of 32 Mt per year allowed under the Alberta emissions cap would make achieving Canada's climate commitments less onerous and provide even more surplus capacity on the export pipeline system.

In summary, Canada does not need TMEP nor does it need other tidewater pipelines such as Energy East. The US is not unfairly discounting Canada's oil and no Asia price premium exists. The construction of the Line 3 expansion and Keystone XL pipelines with the Trump administration's support will allow access to the highest prices available and provide surplus export pipeline capacity. Politicians knew this information, or should have known it, when TMEP was approved in November 2016.

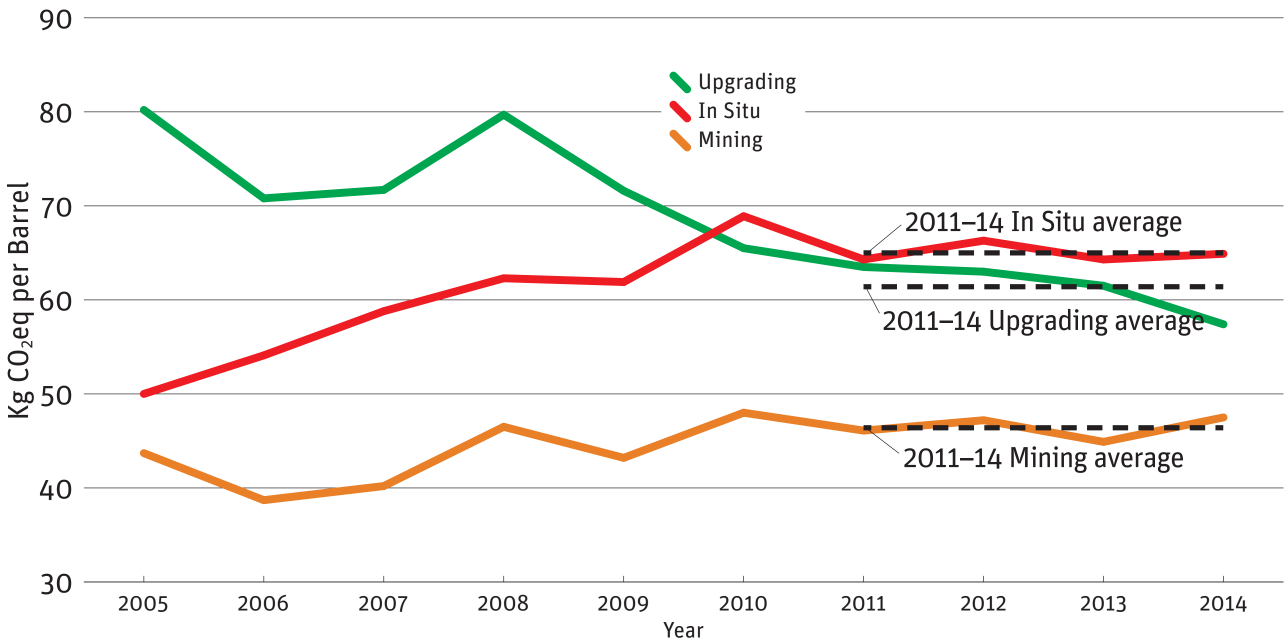
Canada's remaining fossil fuels are valuable and will likely be needed at some level for the foreseeable future. Given their finite nature, and the environmental and climate implications of their use, they deserve the fullest assessment of the facts in the context of a long-term strategy. Canada has no energy strategy beyond liquidating its remaining resources as fast as possible to serve the economic interests of the government of the day. Increasing oil and gas production while trying to reduce emissions are conflicting priorities. A comprehensive energy strategy that addresses the future energy security of Canadians and Canada's international climate commitments should be a national priority.

Appendix A: Calculation of oil sands production under Alberta's emissions cap

ALTHOUGH GREENHOUSE GAS emissions for upgrading have improved significantly through the use of technologies such as cogeneration that produce both heat and power, emissions per barrel for extraction by in situ and mining methods has been essentially flat in recent years. Furthermore, the NEB forecasts that most of the future growth in oil sands production will be from in situ methods — the extraction method with the highest GHG emissions.

The NEB points out that steam-oil ratios (SORs, the number of units of steam required to produce a unit of oil), which directly correlate with emissions from in situ extraction, may increase over the longer term as new projects move into lower-quality reservoirs with higher steam requirements and existing reservoirs become less efficient as they are exhausted.[42] For this reason, and because emissions per barrel for in situ and mining extraction have shown no discernable improvement in recent years (Table A-1, Figure A-1), future emissions have been projected from an average of the emissions per barrel recorded between 2011 and 2014 using the latest NEB production forecasts.

FIGURE A-1 Oil sands greenhouse gas emissions per barrel for mining and in situ extraction, as well as for upgrading to synthetic crude oil, from 2005 to 2014



Source The data sources are given in Table A-1.

TABLE A-1 Oil sands emissions by extraction method and upgrading plus average emissions per barrel of oil, 2005 to 2014

Year	Oil sands emissions (Mt/year)			Oil sands production (kbd)			Average emissions per barrel of oil ($kgCO_2eq/bbl$)[41]		
	Mining	In situ	Upgrading	Mining	In situ	Upgrading	Mining	In situ	Upgrading
2005	10	8	16	626	438	547	43.7	50.0	80.2
2006	10.75	9.75	17	760	494	658	38.7	54.1	70.8
2007	11.5	11.5	18	784	536	687	40.2	58.8	71.7
2008	12.25	13.25	19	721	583	654	46.5	62.3	79.7
2009	13	15	20	825	664	765	43.2	61.9	71.6
2010	15	19	19	857	755	794	48.0	68.9	65.5
2011	15	20	20	892	852	862	46.1	64.3	63.5
2012	16	24	21	930	992	913	47.2	66.3	63.0
2013	16	26	21	976	1108	936	44.9	64.3	61.5
2014	18	30	20	1038	1266	954	47.5	64.9	57.4
2011–2014 average used to calculate emissions cap							**46.4**	**65.0**	**61.4**

Source Data on oil sands emissions by extraction method and upgrading are from Environment Canada, *National Inventory Report 1990–2014: Greenhouse Gas Sources and Sinks in Canada, 3 parts* (Gatineau: Environment Canada, 2016). Average emissions per barrel are calculated from these data using oil production figures in National Energy Board, *Canada's Energy Future 2016: Update — Energy Supply and Demand Projections to 2040.*

Appendix B: Surplus export capacity with Line 3 and Keystone XL

Table B-1 illustrates peak Western Canadian oil supply and pipeline and rail capacity if the Line 3 project and Keystone XL pipelines are built. At peak production in 2026 in the NEB reference case, there is a 13 per cent surplus in pipeline-only capacity and a 23 per cent surplus in pipeline plus rail capacity.

TABLE B-1 Peak Western Canadian oil supply under the Alberta emissions cap compared to available pipeline and rail capacity if the Line 3 project and Keystone XL pipelines are built

	Western Canadian supply with 100 Mt per year emissions cap (mbd)	Peak year	Surplus pipelines only with 95% availability (%)	Surplus pipelines plus rail (%)
NEB reference peak	5.02	2026	13.2	23.2
NEB high price peak	5.13	2026	11.3	21.6
NEB low price peak	5.06	2031	12.5	22.6

Source Author calculations based on Environment Canada, *National Inventory Report 1990–2014: Greenhouse Gas Sources and Sinks in Canada*, pipeline capacity from sources in Table 1, and production forecasts from National Energy Board, *Canada's Energy Future 2016: Update — Energy Supply and Demand Projections to 2040*.

Appendix C: Uncertainty in the Kinder Morgan benefit analysis

KM'S SUBMISSION TO the NEB (the Muse Stancil report) alleged a $73 billion gain by Canadian oil producers through the development of TMEP. This increase was estimated using Muse Stancil's proprietary Muse Crude Oil Market Optimization Model, which included assumptions about crude oil supply, prices, pipeline capacities and tolls, etc. The model projected, among other things, crude oil volumes moved to various destinations, and changes in oil price for Western Canadian producers which amount to a windfall from TMEP. Muse ran this model twice for each year between 2018 and 2038, once assuming that TMEP was in place and once without. All other variables in the model remained unchanged.

Needless to say, the Muse Crude Oil Market Optimization Model is complex. When the City of Vancouver asked if any sensitivity analysis had been performed to test the model's validity, KM responded, "Sensitivity analysis is not typically employed to test the reliability of linear programming models."[43] (Sensitivity analysis involves changing the input assumptions of the model to assess the impact on the output results.)

Muse referred to the following table (Table C-1), which looked at one year (2025), as evidence that sensitivity analysis had been performed. This analysis compared a "base scenario" with no TMEP, a "lower supply scenario"

TABLE C-1 Muse sensitivity analysis showing change in oil prices in 2025 with a drop of 500 kbd in Canadian supply (lower supply scenario) compared to TMEP removing 500 kbd from North America through Asian exports

Crude oil type	Base scenario	Lower supply scenario	TMEP scenario	Lower supply less Base	TMEP less Base	Difference TMEP less Lower supply scenario
Canadian Light Sweet	78.69	79.58	79.58	0.89	0.89	**0.00**
Canadian Medium Sour	74.92	76.14	76.13	1.21	1.21	**0.00**
Sweet Synthetic	79.35	80.85	81.28	1.50	1.93	**0.43**
Conventional Heavy (LLB)	63.92	66.02	65.69	2.10	1.78	**–0.32**
Western Canadian Select	64.03	66.07	65.84	2.03	1.81	**–0.22**
Cold Lake Blend	61.80	64.03	63.69	2.23	1.89	**–0.34**
Athabasca DilBit	57.76	59.98	60.13	2.23	2.37	**0.14**
Athabasca SynBit	64.18	66.43	67.52	2.26	3.34	**1.08**
Sour Synthetic	73.67	75.36	75.78	1.69	2.11	**0.42**

Source Data from *Market Prospects and Benefits Analysis of the Trans Mountain Expansion Project for Trans Mountain Pipeline (ULC)*, September 2015, page 11.

with no TMEP and a 500 kbd supply reduction, and a "TMEP scenario" that decreased supply by 500 kbd through exports to Asia. The results show that Muse's inferred increase in prices due to TMEP is virtually equal to lowering supply by the same amount without TMEP. Some crude oil prices are reduced by up to US$0.34 per barrel and others are increased by up to US$1.08.

When Metro Vancouver queried if confidence intervals were employed to assess potential uncertainty in the model's results, KM noted, "Muse does not generally use this capability [confidence intervals]. The model results, in the terminology used in the request, can be considered to be certain."[44] (Confidence intervals assess the probability of a result being correct, given the uncertainties in input assumptions, and are usually expressed as a percentage.)

In a separate response to Metro Vancouver on the Muse report, KM stated, "The key risk and uncertainty, in the context of the Project, is the future supply of Western Canadian crude oil."[45]

As noted above, the Muse report vastly overestimated Western Canadian oil supply as it did not incorporate the Alberta oil sands emissions cap and relied on a very high supply scenario—equivalent to the NEB's high price scenario in its updated 2016 projections. Muse also did not anticipate other pipelines that are likely to be built, which KM indicated in response to a query from the Tsawout First Nation would have an impact on the benefit estimate from the Muse model: “The inclusion of any of the excluded pipelines will affect the TMEP benefit estimate.”[46]

By KM’s own admission, each of these omissions taken separately, let alone together, would invalidate the “benefit estimate” calculated for TMEP in KM’s submission to the NEB.

Notes

1 See, for example, Alberta Premier Rachel Notley's quote in a feature about the Trans Mountain pipeline on *The Current*. Jeff Rubin in conversation with Kelly Crowe, *The Current*, CBC Radio 1, December 2, 2016, http://www.cbc.ca/radio/thecurrent/the-current-for-december-2-2016-1.3876956/december-2-2016-full-episode-transcript-1.3879302.

2 Trans Mountain Pipeline ULC, "Trans Mountain Response to NEB Replacement Evidence Information Request," B430-2, October 2015, page 38, https://apps.neb-one.gc.ca/REGDOCS/File/Download/2839553.

3 "US Spending Bill Lifts 40-Year Ban on Crude Oil Exports," BBC News, December 18, 2015, http://www.bbc.com/news/business-35136831.

4 Muse Stancil, *Market Prospects and Benefits Analysis of the Trans Mountain Expansion Project for Trans Mountain Pipeline (ULC)*, B427-2 2a, September 2015, https://docs.neb-one.gc.ca/ll-eng/llisapi.dll/fetch/2000/90464/90552/548311/956726/2392873/2451003/2825642/B427-2_-_2a_Muse_Stancil%2C_Market_Prospects_and_Benefits_Analysis_of_the_TMEP%2C_September_2015_-_A4T6E8.pdf?nodeid=2825856&vernum=-2.

5 The Conference Board of Canada, *The Trans Mountain Expansion Project: Understanding the Economic Benefits for Canada and Its Regions* (Ottawa: The Conference Board of Canada, September 2015), https://apps.neb-one.gc.ca/REGDOCS/File/Download/2825199.

6 National Energy Board, Canada's Energy Future 2016: Update–Energy Supply and Demand Projections to 2040, B427-4 3a (Ottawa: National Energy Board, 2016), https://www.neb-one.gc.ca/nrg/ntgrtd/ftr/2016updt/2016updt-eng.pdf.

7 "Reference" refers to the most likely production scenario; "high price" is the production scenario if oil prices are higher than expected and "low price" is the production scenario if oil prices are lower than expected.

8 The Legislative Assembly of Alberta, Bill 25 (Oil Sands Emissions Limit Act), December 2016. See http://www.assembly.ab.ca/ISYS/LADDAR_files/docs/bills/bill/legislature_29/session_2/20160308_bill-025.pdf. See also https://albertandpcaucus.ca/our-work/project/fall-2016-bill-25-oil-sands-emissions-limit-act.

9 Refinery consumption as of 2019 according to Canadian Association of Petroleum Producers, 2016 CAPP Crude Oil Forecast, Markets & Transportation (Calgary: CAPP, *2016). If built, TMEP would be completed by this date.*

10 "Tidewater" refers to ocean access and the capability to transport oil to overseas markets via tankers.

11 "Net capacity" is the effective capacity after allowance for maintenance and other outages. "Nameplate capacity" is the maximum possible pipeline throughput.

12 Trans Mountain Pipeline ULC, "Trans Mountain Response to NEB Replacement Evidence Information Request," Table 1a.1, page 4, note 250. Note that kilobarrels per day (kbd) of capacity for the existing Trans Mountain pipeline was added to the total of "other pipelines" in this table to determine export capacity from the Western Canadian Sedimentary Basin (WCSB), https://apps.neb-one.gc.ca/REGDOCS/Item/View/2839659. See also Trans Mountain Pipeline ULC, "Trans Mountain Response to Tsawout First Nation Replacement Evidence Information Request," B430-6, October 2015, see Table 1.1d.1, page 4, https://apps.neb-one.gc.ca/REGDOCS/File/Download/2839997.

13 Nia Williams and Ethan Lou, "Canada's Trudeau says Trump Very Supportive of Keystone XL Pipeline," Reuters, December 21, 2016, http://www.reuters.com/article/us-canada-energy-trudeau-idUSKBN14A1S0.

14 The White House, "Remarks by the President in TransCanada Keystone XL Pipeline Announcement," press release, March 24, 2017, https://www.whitehouse.gov/the-press-office/2017/03/24/remarks-they-president-transcanada-keystone-xl-pipeline-announcement.

15 Nicole Gibillini, "Keystone XL The 'Single Best' Pipeline for Canada, Says Former Transcanada and Talisman CEO," BNN, December 6, 2016, http://www.bnn.ca/keystone-xl-the-single-best-pipeline-for-canada-says-former-transcanada-and-talisman-ceo-1.625045.

16 National Energy Board, *National Energy Board Report: Trans Mountain Expansion Project, May 2016,* A77045-1, (Calgary: National Energy Board, 2016), page 295, https://apps.neb-one.gc.ca/REGDOCS/File/Download/2969681.

17 The Conference Board of Canada, *The Trans Mountain Expansion Project: Understanding the Economic Benefits for Canada and Its Regions.*

18 Note that some additional price differential between Western Canadian Select (WCS) oil sold in the US Midwest and West Texas Intermediate (WTI) during the 2012–2014 period was due to pipeline congestion between the US Midwest and Cushing, Oklahoma, which has since been eliminated. See Oil Change International, "Tar Sands: The Myth of Tidewater Access," March 2016, http://priceofoil.org/content/uploads/2016/05/Tidewater-2016-v2.pdf.]

19 US Energy Information Administration via IndexMundi, accessed December 9, 2016, http://www.indexmundi.com/commodities/.

20 Brent is the international price used to calculate the Maya quality discount. It could alternatively be compared to WTI at Houston, provided the toll (about US$1.35 per barrel) to move oil from Cushing, where the WTI benchmark is set, to Houston was added to the WTI at Houston price.

21 Baytex Energy, Untitled list of WCS historical prices, accessed December 6, 2016, http://www.baytexenergy.com/files/pdf/Operations/Historical_WCS_Pricing_October_2016.pdf.

22 Argus Americas Crude, "Crude Market Prices and Analysis," Issue 16-184, September 23, 2016, accessed April 4, 2017, https://www.argusmedia.com/~/media/files/pdfs/samples/argus-americas-crude.pdf/?la=en.

23 Jason Markusoff, "Rachel Notley Takes on Pipeline Critics — Even If They're from Her Party," *Maclean's,* December 7, 2016, http://www.macleans.ca/politics/rachel-notley-takes-on-pipeline-critics-even-if-theyre-from-her-party/.

24 US Energy Information Administration, "Crude Oil Production," accessed December 15, 2016, http://www.eia.gov/dnav/pet/pet_crd_crpdn_adc_mbblpd_m.htm.

25 BP, *BP Statistical Review of World Energy, 2016* (London, BP, 2016), http://www.bp.com/content/dam/bp/pdf/energy-economics/statistical-review-2016/bp-statistical-review-of-world-energy-2016-full-report.pdf.

26 Muse Stancil, *Market Prospects and Benefits Analysis of the Trans Mountain Expansion Project for Trans Mountain Pipeline (ULC),* Table A-16, page 80.

27 Muse Stancil, *Market Prospects and Benefits Analysis of the Trans Mountain Expansion Project for Trans Mountain Pipeline (ULC),* Table A-14, page 78.

28 National Energy Board, *Canada's Energy Future 2016,* see Appendices.

29 Muse Stancil, *Market Prospects and Benefits Analysis of the Trans Mountain Expansion Project for Trans Mountain Pipeline (ULC)*, Author calculations based on Tables A-10 through A-13, pages 71–77.

30 Muse Stancil, *Market Prospects and Benefits Analysis of the Trans Mountain Expansion Project for Trans Mountain Pipeline (ULC),* author calculations based on Tables A-6 and A-7, pages 67–68.

31 These data come from a subscription service, Platts Commodity News, shown to me by Oil Change International on December 7, 2016.

32 Trans Mountain Pipeline ULC, "Trans Mountain Response to Tsawout First Nation Replacement Evidence Information Request," page 22, https://apps.neb-one.gc.ca/REGDOCS/File/Download/2839997.

33 "Committed" refers to a long-term contract rate; "spot" refers to a short-term or one-time agreement rate.

34 Muse Stancil, *Market Prospects and Benefits Analysis of the Trans Mountain Expansion Project for Trans Mountain Pipeline (ULC),* Tables A-2 and A-3, pages 61–62 (tanker voyage tolls are an average of northeast Asia destinations, and committed not spot tolls are used).

35 Natural Resources Canada, "Selected Crude Oil Prices Monthly — 2016," accessed December 13, 2016, http://www.nrcan.gc.ca/energy/fuel-prices/crude/17087.

36 Canadian Association of Petroleum Producers, "Canadian and U.S. Crude Oil Pipelines and Refineries," June 2016, http://www.capp.ca/~/media/capp/customer-portal/documents/284954.pdf (committed price); low price from Argus reference cited in Table 2.

37 Letter from Rachel Notley to the National Energy Board Hearing Order OH-001-2014 — Trans Mountain Expansion Project, C142-2-2, undated, https://apps.neb-one.gc.ca/REGDOCS/File/Download/2905513.

38 Marc Lee, "Kinder Morgan's Pipeline Sales Pitch: Too Good To Be True?," PolicyNote, Canadian Centre for Policy Alternatives, December 8, 2016, http://www.policynote.ca/pipeline-sales-pitch/. Employment numbers based on Kinder Morgan's submission to NEB by Tera Environmental Consultants, Dec 2013, "Environmental and Socio-economic Assessment for the Trans Mountain Pipeline ULC Trans Mountain Expansion Project, Volume 5B: ESA-Socio-Economic", See page 2–17, Section 2.3.4, https://apps.neb-one.gc.ca/REGDOCS/File/Download/2392986.

39 Jeff Rubin, "New Pipelines? The Oil Sands May Have Trouble Filling The Ones It Has," *The Globe and Mail,* November 1, 2016, http://www.theglobeandmail.com/report-on-business/rob-commentary/new-pipelines-the-oil-sands-mayhave-trouble-filling-the-ones-it-has/article32601876/.

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