Trans Mountain Pipeline ULC Application for the Trans Mountain Expansion Project

National Energy Board reconsideration of aspects of its Recommendation Report as directed by Order in Council P.C. 2018-1177

File OF-Fac-Oil-T260-2013-03 59, Hearing Order MH-052-2018

Report on the Need For, and Economics Of, the Trans Mountain Expansion Project

Prepared for

Tsleil-Waututh Nation, Squamish Nation, Stz'uminus First Nation, and Snuneymuxw First Nation

Prepared by

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1.0 EXECUTIVE SUMMARY

1. I have been retained by the Tsleil-Waututh Nation, Squamish Nation, Stz'uminus First Nation, and Snuneymuxw First Nation to assess the need for, and Project economics, of the Trans Mountain Expansion Project (Project). In particular, I have been asked to provide my professional opinion on the following three questions:

   (a) Have there been any significant developments since the completion of Trans Mountain's analysis and the National Energy Board's (NEB) 2016 report on the Project that materially affect the conclusions regarding the need for and the benefits of the Project?

   (b) Based on the recent developments assessed in question (a):

      (i) Is there a need for the Project?

      (ii) Will the Project increase the price per barrel of oil that Canadian producer are able to obtain?

2. There have been the following material changes since the completion Trans Mountain's analysis that materially affect the conclusions the NEB reached in its 2016 report in connection with the need for and benefits of the Project:

   (a) Estimates of the cost of building the Project have increased significantly since the completion of Trans Mountain's analysis of the benefits of the Project. Increased costs of building the Project impact the cost of shipping on the Project relative to alternatives and render the estimate of the benefits of the Project by Trans Mountain in their application and other evidence they filed in the initial NEB hearing for the Project dated and inaccurate.

   (b) New Western Canadian Sedimentary Basin (WCSB) pipeline export capacity has been approved since the NEB's initial hearing for the Project. New pipeline export capacity approved includes:

      (i) the Enbridge Line 3 replacement project which received final approvals from the U.S. in June 2018 and is currently under construction, with an in-service date of late 2019; and

      (ii) the TransCanada Keystone XL pipeline that was approved by President Trump in March 2017, with a likely in-service date of 2021, pending an additional environmental review ordered by U.S. courts.[1]

   These two projects, totaling 1.2 million barrels per day, will add twice the export capacity of the Project.

[1] The recent lower court ruling against Keystone XL in November 2018 will require a revised environmental assessment unless the decision is overturned by an appeal. Given that TransCanada was not planning to start major construction until 2019, it may not significantly delay the planned 2021 in-service date. TransCanada has also indicated that this court decision is manageable and that it remains committed to the project https://business.financialpost.com/commodities/energy/transcanada-open-minded-about-joint-venture-partner-for-10-billion-keystone-xl-pipeline .

In addition, Enbridge plans to expand its Mainline by 0.45 million barrels per day, for a combined pipeline export capacity increase of 1.65 million barrels per day, or nearly three times the capacity of the Project.

(c) New oil production forecasts by the Canadian Association of Petroleum Producers (CAPP) and the NEB have been produced that are relevant to forecasting the need for and benefits of the Project.

(d) Recent market trends related to a tightening of WCSB export pipeline capacity and increased discounts in the price of WCSB oil illustrate the short-term need for new WCSB transportation capacity.

The implications of these recent developments are assessed in this report

3. In answer to the second question on the need for the Project, the latest NEB and CAPP estimates of future oil supply from the WCSB were examined in the light of existing, in construction, and planned pipeline and rail export capacity, and recent oil production forecasts. The impact of the Alberta Government's 100 megatonne (Mt) per year cap on oil sands emissions was also evaluated for its impact on supply. Critical findings include:

(a) New pipeline export capacity with scheduled in-service dates in the next few years (Line 3, Enbridge Mainline, and Keystone XL) will provide sufficient pipeline capacity to meet WCSB oil transportation needs until 2031 based on the NEB reference case production oil forecast and until 2033 based on the CAPP supply forecast, without using rail and without the Project. This new pipeline export capacity will address the current shortage of pipeline space and eliminate the current high WCSB price discounts.[2]

(b) Meeting Alberta's 100 megatonne (Mt) cap on oil sands emissions will constrain Western Canadian oil production growth in all of the NEB's scenarios except the low price case, which doesn't reach the annual 100 Mt emissions limit. The emissions cap will have the following implications for WCSB transportation needs:

(i) Existing and new pipeline export capacity (Enbridge Line 3 and Mainline expansions) are sufficient to meet WCSB transportation needs under the NEB low price, technology, and reference case to 2036 without the Project, Keystone XL and without using rail.

(ii) The NEB reference case would require a small amount of available rail capacity under the cap without Keystone XL, and no rail with it.

(c) Meeting Canada's emissions reduction targets under the Paris Agreement and 2050 aspirations will require further downward pressure on Western Canadian supply beyond Alberta's oil sands emissions cap. The NEB's reference case supply projection, with the cap, would require sectors in the economy outside of oil and gas production to reduce emissions 48% by 2030 and 88% by 2040, which would be very difficult without further cuts to oil and gas production.

4. In answer to the third question, pipeline and tanker tolls from Edmonton to south China were determined for the Project from Trans Mountain's submissions and compared to CAPP's

[2] The very high oil sands production growth under the NEB's high price case is considered extremely unlikely, even if its price scenario did materialize, due to the emissions implications, capital cost, and infrastructure expansion required, and therefore the high price case is not considered further in this report.

estimate of tolls from Hardisty to the U.S. mid-west and U.S. Gulf Coast. Selling prices in Far East and U.S. Gulf Coast markets for Maya heavy, sour crude oil, which is a comparable grade to Canada's Western Canadian Select (WCS) benchmark, were also compared to estimate what WCS would fetch in each market. Critical findings include:

(a) Combined tanker and pipeline tolls for crude oil shipped on the Project to south China are likely to be between $US2.68 and $US3.08 per barrel higher than tolls to the complex refineries on the U.S. Gulf Coast, and $US5.63 to $US6.03 per barrel higher than tolls to complex refineries in the U.S. mid-west (complex refineries are optimized for heavy oil). These higher tolls of shipping crude oil on the Project to Asia compared to shipping crude oil to the U.S. Gulf Coast could cost Canadian producers between $CAN14.0 and $CAN16.1 billion over a 21-year operating period for the Project.

(b) The average price over the past 12 months of WCS-equivalent heavy, sour crude oil is $US1.04 per barrel higher for deliveries to the U.S. Gulf Coast compared to deliveries to Asian markets (from 2013 to 2017 U.S. Gulf Coast prices averaged $US3.46 per barrel higher than Asian markets). Although the volume of Canadian heavy, sour crude deliveries to the U.S. Gulf Coast is still relatively small, it has increased 318% since 2010, whereas deliveries from traditional suppliers in Mexico and Venezuela have declined by 40%, owing to declining production in both countries. Canadian heavy oil is an ideal replacement for declining imports from these traditional suppliers. New pipeline export capacity under development will allow increased access to the U.S Gulf Coast market, which provides a very attractive market for WCSB oil.

If the premium for heavy oil on the U.S. Gulf Coast compared to the Far East observed over the past six years persists, losses to producers shipping on the Project to Asia would be significantly higher (each $US1.00 premium on the US Gulf Coast versus Asian markets confers an additional $CAN5.2 billion loss selling oil to Asia via the Project over a 21-year project life - the U.S. Gulf Coast premium has averaged $US3.06 over the past six years).[3] This compares to Trans Mountain's 2015 submission to the NEB, which states that the Project will provide a benefit of $CAN73.5 billion for Canadian producers.[4] Based on the analysis of tolls, prices and new projects noted above, Trans Mountain's estimate is stale-dated, inaccurate, and cannot be relied upon.

(c) Trans Mountain's estimate of the benefit the Project will provide to Canadian producers is based on the erroneous assumption that if Project is not built, WCSB oil would have to be shipped by rail. This assumption is stale-dated and inaccurate. WCSB oil will be shipped on Enbridge and TransCanada pipelines to the U.S. Gulf Coast and mid-west if the Project is not built, and will capture higher prices than shipping to Asia via the Project.

5. In conclusion, recent developments since completion of the NEB's 2016 report have confirmed that the Project is not needed and building the Project would likely impart a substantial price penalty to Canadian producers compared to other pipeline export capacity likely to come on-stream before the Project could be built. This other pipeline export capacity will meet the long-term transportation needs of WCSB producers and eliminate the current pipeline export capacity shortage and the current high WCSB price discounts.

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[3] Trans Mountain submission of Muse-Stancil report, September 2015, Market prospects and benefits analysis of the Trans Mountain Expansion Project for Trans Mountain Pipeline (ULC). See Table 2.

2.0 INTRODUCTION

2.1 Scope of work

6. I have been retained by the Tsleil-Waututh Nation, Squamish Nation, Stz'uminus First Nation, and Snuneymuxw First Nation to assess the need for, and Project economics, of the Project. In particular, I have been asked to provide my professional opinion on the following three questions:

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   (b) Based on the recent developments assessed in question (a):

      (i) Is there a need for the Project?

      (ii) Will the Project increase the price per barrel of oil that Canadian producer are able to obtain?

2.2 Statement of qualifications

7. David Hughes is an earth scientist that has studied the energy resources of Canada and the U.S. for more than four decades, including 32 years with the Geological Survey of Canada as a scientist and research manager. He is president of Global Sustainability Research Inc., a consultancy that has analyzed the geological fundamentals and production potential of unconventional oil and gas plays across Canada and the U.S. He has published and lectured widely on energy and sustainability issues in North America and internationally. He is also a Fellow of Post Carbon Institute, a Board member of Physicians, Scientists and Engineers for Healthy Energy and a Research Associate with the Canadian Centre for Policy Alternatives.

8. Hughes holds a First Class Honours Bachelor of Science degree and a Master of Science degree, both in Geology, from the University of Alberta. He has participated previously as an expert witness in NEB hearings on the Northern Gateway and North Montney Mainline pipelines. Further details are attached in **Appendix 1**.

2.3 Expert's duty

9. I have prepared this report in accordance with my duty as an expert to assist: (i) TWN in conducting its assessment of the Project; (ii) provincial or federal authorities with powers, duties or functions in relation to an assessment of the environmental and socio-economic effects of the Project; and (iii) any court seized with an action, judicial review, appeal or any other proceeding in relation to the Project. A signed copy of my Certificate of Expert's Duty is attached as **Appendix 2**.

2.4 Documents reviewed

10. The documents reviewed are cited where they are referenced in the following text. They include the NEB Canada's Energy Future 2018 report, the 2018 Canadian Association of Petroleum Producers Western Canadian oil supply forecast, various documents Trans Mountain submitted to the NEB, the 2018 Environment and Climate Change Canada (ECCC) National Inventory Report on emissions submitted to the United Nations, and various other documents.

3.0 HAVE THERE BEEN ANY SIGNIFICANT DEVELOPMENTS SINCE THE COMPLETION OF TRANS MOUNTAIN'S ANALYSIS AND THE NEB'S 2016 REPORT ON THE PROJECT THAT MATERIALLY AFFECT THE CONCLUSIONS REGARDING THE NEED FOR AND THE BENEFITS OF THE PROJECT?

11. There have been the following material changes since the completion Trans Mountain's analysis and the NEB's report that affect the conclusions regarding the need for and benefits of the Project:

(a) Estimates of the cost of building the Project have increased significantly since the completion of Trans Mountain's analysis of the benefits of the Project. Increased costs of building the Project impact the cost of shipping on the Project relative to alternatives and render the estimate of the benefits of the Project by Trans Mountain in their application and other evidence they filed in the initial NEB hearing for the Project dated and inaccurate.

(b) New WCSB pipeline export capacity has been approved since the NEB's initial hearing for the Project. New pipeline export capacity approved includes:

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These two projects, totaling 1.2 million barrels per day, will add twice the export capacity of the Project.

In addition, Enbridge plans to expand its mainline by 0.45 million barrels per day, for a combined pipeline export capacity increase of 1.65 million barrels per day, or nearly three times the capacity of the Project.

(c) New oil production forecasts by the CAPP and the NEB have been produced that are relevant to forecasting the need for and benefits of the Project.

(d) Recent market trends related to a tightening of WCSB export pipeline capacity and increased discounts in the price of WCSB oil illustrate the need for new WCSB transportation capacity.

4.0 IS THERE A NEED FOR THE TRANS MOUNTAIN EXPANSION PROJECT?

4.1 The current supply forecast for WCSB crude from 2018-2030

[5] The recent lower court ruling against Keystone XL in November 2018 will require a revised environmental assessment unless the decision is overturned by an appeal. Given that TransCanada was not planning to start major construction until 2019, it may not significantly delay the planned 2021 in-service date. TransCanada has also indicated that this court decision is manageable and that it remains committed to the project https://business.financialpost.com/commodities/energy/transcanada-open-minded-about-joint-venture-partner-for-10-billion-keystone-xl-pipeline .

12. Figure 1 illustrates Western Canadian supply based on the reference case of the NEB Energy Future 2018 report.[6] The reference case is shown subdivided by product type, including imported and domestic diluent needed to transport raw bitumen. The total supply for the NEB's low price and technology cases are also shown (NEB also has a 'high price' case with very high oil sands production growth that is considered extremely unlikely, even if the assumed prices materialized, due to the emissions implications, capital cost, and infrastructure needed, and is therefore not considered further in this report). CAPP's 2018 Western Canadian supply forecast is shown for comparison.[7] There is broad agreement between the NEB's reference case and CAPP's forecast, with the NEB reference case being slightly higher than CAPP beyond 2030.

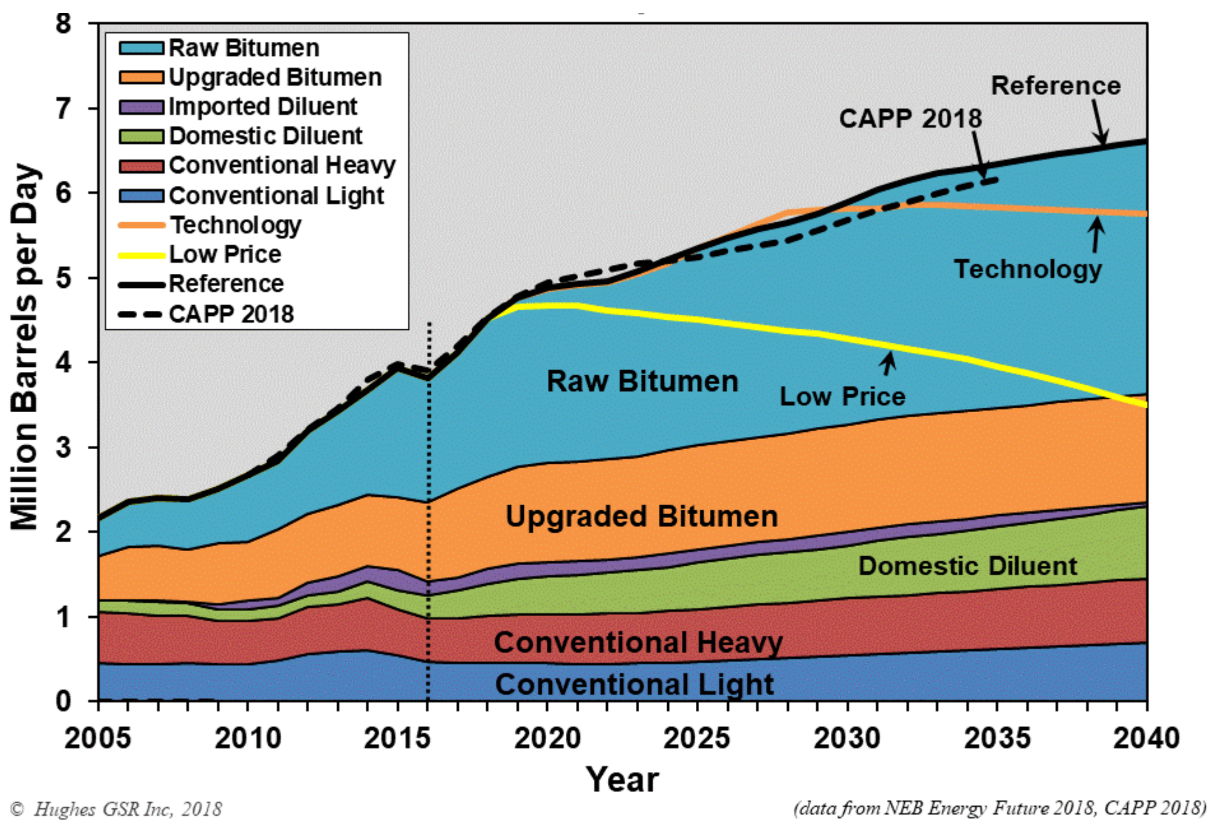

Figure 1 – Western Canadian oil supply in the NEB 2018 reference case from 2005 to 2040. Also shown are the NEB's low price and technology cases.[8] CAPP's 2018 Western Canadian Supply forecast is shown for comparison.

4.2 Impact of Canada and Alberta's climate change commitments on the current supply forecast for WCSB crude from 2018-2030

[6] National Energy Board, 2018, Canada's Energy Future 2018: An energy market assessment. Data are from the Appendices https://apps.neb-one.gc.ca/ftrppndc/dflt.aspx?GoCTemplateCulture=en-CA . The NEB report projects bitumen production from mining and in situ methods and output from upgraders. The supply was calculated by determining the amount of raw and upgraded bitumen that would be shipped and the volume of imported diluent that would be needed after considering domestic diluent production.

[7] Canadian Association of Petroleum Producers, 2018 Crude Oil Forecast: MARKETS AND TRANSPORTATION. Data are from the data tables associated with this report http://www.capp.ca/~/media/capp/customer-portal/publications/320292src

[8] Supply was determined from NEB 2018 estimates of raw bitumen and upgraded bitumen to estimate the proportion of raw bitumen that would be sold in non-upgraded form and would require imported diluent for blending (assuming a 30% diluent to bitumen blending rate).

13. As part of its Climate Leadership Plan, Alberta has implemented a cap on oil sands emissions at 100 Mt per year, which is an increase of 28 Mt from 2016 levels.[9] ECCC submits an annual estimate of emissions to the UN, which estimates emissions from oil sands mining, in situ recovery and upgrading.[10] Emissions per barrel can be determined using these estimates, as well as the NEB estimates of yearly production, as set out in Table 1.

Year	Oil Sands Emissions (Mt/year)			Oil Sands Production (kbd)			Emissions (KgCO2eq/bbl)		
	Mining	In Situ	Upgrading	Mining	In Situ	Upgrading	Mining	In Situ	Upgrading
2005	9	11	14	626	438	522	39.4	68.7	73.5
2006	11	13	16	760	494	619	39.6	72.1	70.8
2007	12	13	17	784	536	652	41.9	66.5	71.4
2008	12	17	16	721	583	620	45.6	79.9	70.7
2009	13	18	18	825	664	722	43.2	74.3	68.3
2010	14	20	19	857	752	703	44.8	72.8	74.1
2011	14	22	19	893	847	810	43.0	71.1	64.2
2012	14	25	20	932	990	817	41.1	69.2	67.1
2013	15	28	20	976	1106	835	42.1	69.4	65.6
2014	17	30	20	960	1263	842	48.5	65.1	65.0
2015	17	34	19	1161	1362	850	40.1	68.4	61.2
2016	17	37	17	1150	1398	932	40.5	72.5	50.0
2013-2016 average used to calculate emissions							42.8	68.8	60.5

Table 1 – Emissions, production, and calculated emissions per barrel for mining, in situ, and upgrading from 2005 to 2016 based on NEB production[11] and ECCC emissions data.[12] The average of 2013 to 2016 emissions per barrel was used to determine greenhouse gas emissions for the NEB 2018 production projections. Kbd = thousand barrels per day.

14. Although the NEB is optimistic that the increased use of solvents will significantly reduce emissions per barrel for in situ methods of extraction after 2025, a review of operating projects reveals that there is no commercial scale application of this technology. Furthermore, a review of under construction, announced, approved, and applied for projects reveals little solvent extraction use is planned.[13] Steam-oil ratios (SOR) also tend to increase as projects age and extract the last oil from wells, and new projects in lesser quality deposits tend to have higher steam-oil ratios. These factors will offset better technology going forward, making the projection using the past four years of emissions intensity reasonable compared to the assumption of much lower emissions after 2025 from widespread application of as yet non-commercial technology.

15. The NEB's assumptions of better technology apply mainly to the in situ oil sands, which are very energy intensive and a major source of emissions from the combustion of natural gas to generate steam. The steam used per barrel of oil recovered (steam to oil ratio or SOR) is a measure of the energy intensity of the extraction process. Figure 2 illustrates the NEB's assumptions for SOR improvement in its reference case projection compared to the 2013 to 2016 average that I

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[9] Alberta Government, Capping oil sands emissions. Accessed November 3, 2018. https://www.alberta.ca/climate-oilsands-emissions.aspx

[10] Environment and Climate Change Canada, 2018, National Inventory Report submitted to UNFCCC, https://unfccc.int/sites/default/files/resource/can-2018-nir-13apr18.zip

[11] National Energy Board, 2018, Canada's Energy Future 2018: An energy market assessment. Data are from the Appendices https://apps.neb-one.gc.ca/ftrppndc/dflt.aspx?GoCTemplateCulture=en-CA

[12] Environment and Climate Change Canada, 2018, National Inventory Report submitted to UNFCCC, https://unfccc.int/sites/default/files/resource/can-2018-nir-13apr18.zip

[13] JWN active oilsands projects - December 2017. Available at http://www.albertacanada.com/files/albertacanada/JWN-active-oilsands-projects-Dec-2017.xlsx

used to estimate the production implications of the emissions cap. Although there is no improvement through 2025, the NEB forecasts SOR to improve 12% by 2030 and 23% by 2040. The NEB' assumptions are likely incorrect, given the facts outlined above that SOR tends to increase as SAGD projects age and lesser quality deposits are developed. Nonetheless, a scenario with the NEB's assumptions is included below in the section that considers pipeline export capacity.

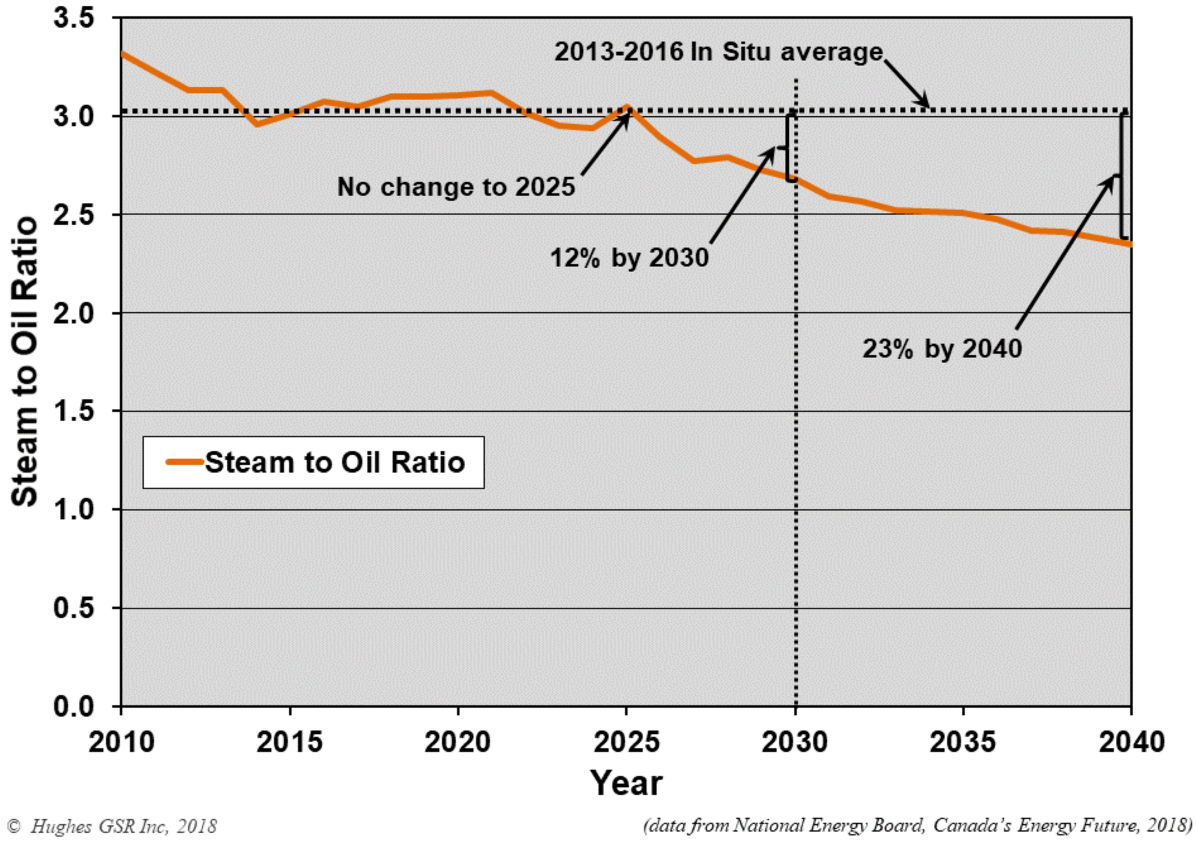


Figure 2 – Change in steam to oil ratios assumed by the NEB in its reference forecast through 2040 compared to the average of 2013 to 2016 that I have used to determine the production impact of Alberta's oil sands emissions cap.[14]

16. Figure 3 shows the calculated NEB reference case oil sands emissions projected to 2040 using the 2013-2016 average emissions per barrel in Table 1. Also shown are aggregate emissions in the NEB's reference case assuming the SOR reductions shown in Figure 2 come to fruition, and aggregate emissions for the NEB's low price and technology cases. Oil sands production and emissions can grow 40% above 2016 levels under Alberta's 100 Mt oil sands emissions cap.

[14] National Energy Board, 2018, Canada's Energy Future 2018: An energy market assessment. See Table 3.10.

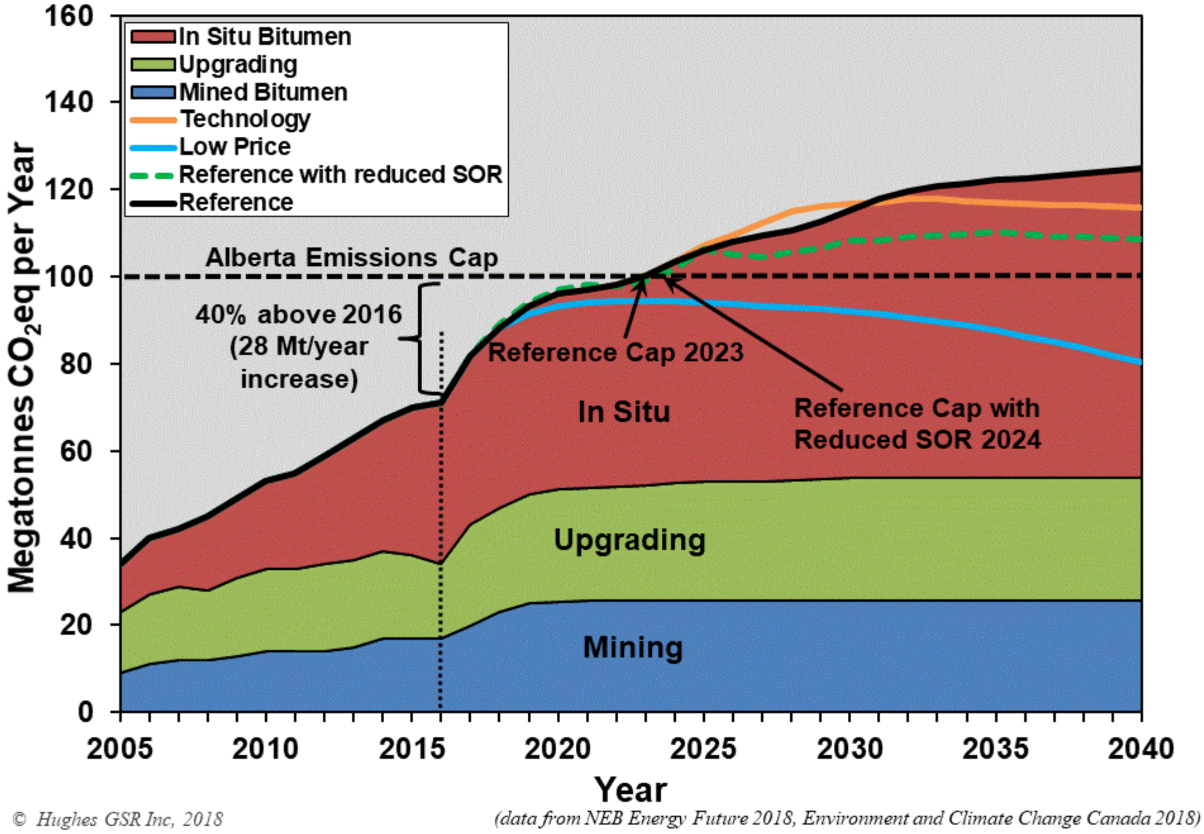


Figure 3 – Oil sands emissions in NEB 2018 reference case showing Alberta's 100 Mt emissions limit as well as aggregate emissions in NEB's low price and technology cases. Emissions are calculated using the 2013-2016 average from the latest ECCC NIR submission to the UN using the data in Table 1.[15] The low price case is not constrained by the cap whereas the reference and technology cases exceed the cap in 2023. Also shown is the NEB reference case with the SOR reductions illustrated in Figure 2 – in this case the emissions cap is exceeded in 2024.

17. Whereas the NEB's low price case never gets to the emissions cap, the reference and technology cases hit the cap in 2023. The reference case with the assumption of reduced SOR hits the cap in 2024.

18. Figure 4 illustrates the effect of the oil sands emissions cap on Western Canadian supply in the NEB's reference case. Other NEB cases are shown with and without the emissions cap. The emissions cap reduces the NEB reference case production by about 0.66 million barrels per day in 2030 and 1.1 million barrels per day in 2040. CAPP's forecast without the cap is 0.46 million barrels per day higher than the NEB reference case with the cap in 2030. The NEB low price case is unaffected by the emissions cap.

[15] Environment and Climate Change Canada, 2018, National Inventory Report submitted to UNFCCC, https://unfccc.int/sites/default/files/resource/can-2018-nir-13apr18.zip

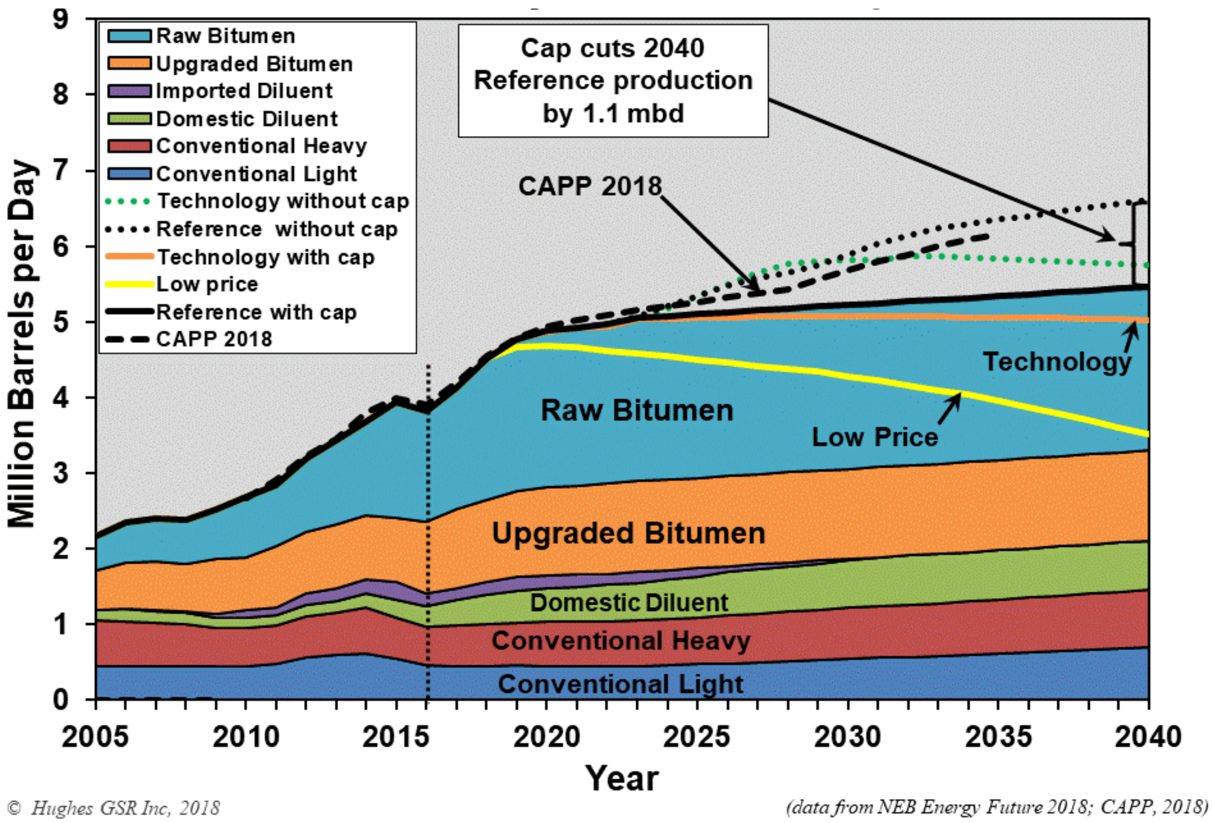
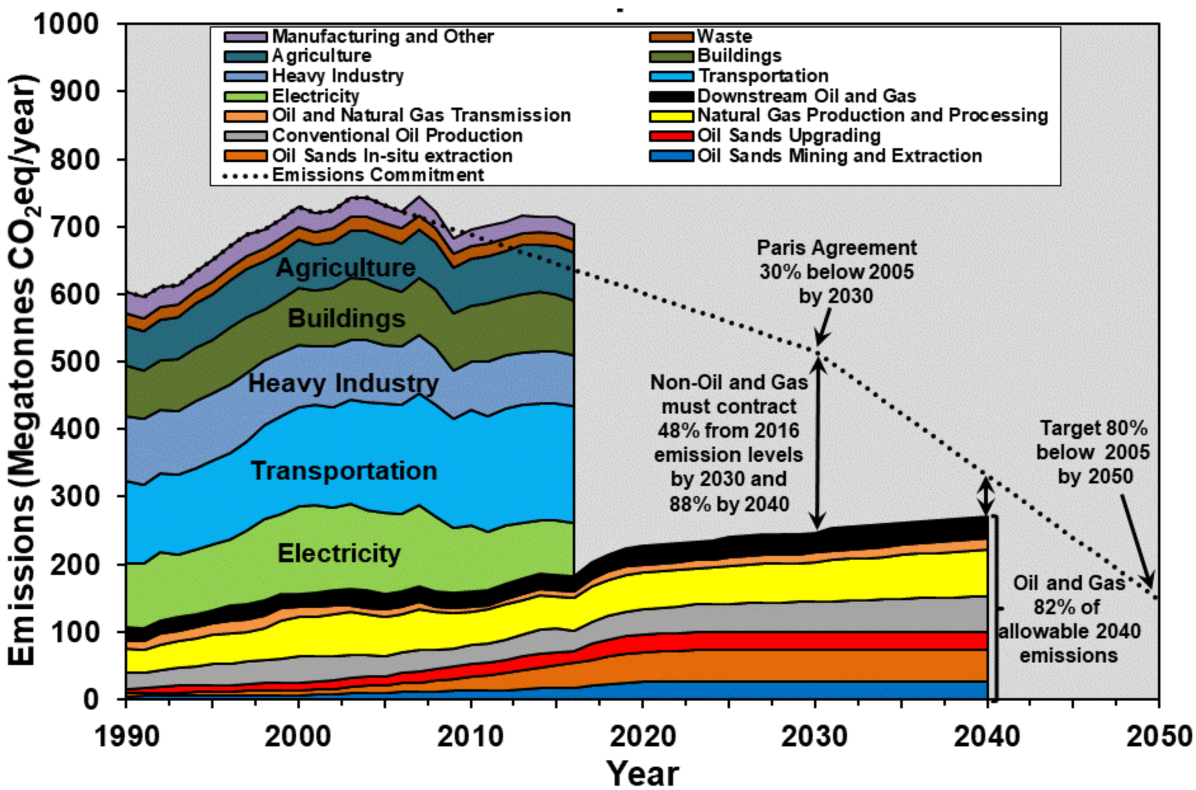


Figure 4 – Western Canadian supply from 2005 to 2040 in NEB's reference case with and without Alberta's 100 Mt oil sands emissions cap. Also shown are NEB's low price and technology cases with and without the emissions cap. CAPP's 2018 Western Canadian supply forecast without the emissions cap is shown for comparison.

19. Notwithstanding that the Alberta oil sand's emissions cap will slow emissions growth, the total scale of emissions reduction required given Canada's commitments under the Paris Agreement will be very difficult to achieve. Figure 5 illustrates emissions from the NEB's reference case production including the 100 Mt oil sands emissions cap. Even with the cap, and assuming emissions from conventional oil and gas production are maintained at the 2013-2016 per unit average, oil and gas production will make up 48% of Canada's allowable emissions limit in 2030 and 82% of its aspirational 2040 limit. This means emissions from the rest of Canada's economy would have to contract 48% by 2030 and 88% by 2040.



© *Hughes GSR Inc, 2018* *(data from ECCC National Inventory Report 2018; NEB Energy Future 2018; Government climate commitments)*

Figure 5 – Emissions by sector from ECCC's National Inventory Report[16] for 1990 to 2016 and calculated from NEB's reference production case[17] for oil and gas production from 2017 through 2040, including Alberta's 100 Mt oil sands emissions cap. Also shown are Canada's commitments under the Paris Agreement (30% reduction from 2005 levels by 2030) and aspirational commitments of 80% below 2005 levels by 2050.

20. Given the magnitude of emission reductions required, it is highly likely that Western Canadian supply for export will have to be reduced far more than projected in the NEB's reference case with the oil sands emissions cap. The NEB's 'low price' case is much more likely in a production scenario where Canada has a chance of meeting its emission reduction targets.

4.3 The supply forecast for WCSB based on completing only existing oil expansion projects under construction

21. Table 2 illustrates projects listed as under construction as of December 2017.[18] In total there are seven projects totaling 318,000 barrels per day. Of these, the Fort Hills mine came on stream in 2018 at a rated capacity of 194,000 barrels per day leaving 124,000 barrels per day of remaining capacity to be built, of which 10,000 barrels per day are for an upgrader not related to bitumen extraction. In addition, Imperial Oil has recently announced that it intends to begin construction on its 75,000 barrel per day Aspen solvent-assisted SAGD project.[19] If all of these projects are

[16] Environment and Climate Change Canada, 2018, National Inventory Report submitted to UNFCCC, https://unfccc.int/sites/default/files/resource/can-2018-nir-13apr18.zip
[17] National Energy Board, 2018, Canada's Energy Future 2018: An energy market assessment. Data are from the Appendices https://apps.neb-one.gc.ca/ftrppndc/dflt.aspx?GoCTemplateCulture=en-CA
[18] JWN active oilsands projects - December 2017. Available at http://www.albertacanada.com/files/albertacanada/JWN-active-oilsands-projects-Dec-2017.xlsx
[19] World Oil, November 8, 2018, Exxon's $2-billion Canada move shows confidence when others flee.

completed in the next few years, Western Canadian supply will be very close to the NEB low price case in Figures 1 and 3, which assumed a price too low to incentivize a significant number of new projects.

Operator Name	Project Name	Phase Name	Technology Description	Capacity (barrels per day)	Year Production Start
Pengrowth Energy Corporation	Lindbergh	Phase 1 Optimization - b	SAGD	1,000	2017
Suncor Energy Inc.	Fort Hills	Phase 1	Surface Mining	194,000	2017
MEG Energy Corp.	Christina Lake	Phase 2B eMSAGP	eMSAGP	20,000	2018
Cenovus Energy Inc.	Christina Lake	Phase G	SAGD	50,000	2019
Canadian Natural Resources Limited	Kirby	KN1 - Kirby North	SAGD	40,000	2020
Canadian Natural Resources Limited	Horizon	Fractionation Tower Debottleneck	Upgrader	10,000	TBD
OSUM Oil Sands Corp.	Orion	Orion Phase 2B	SAGD	3,000	TBD

Table 2 – Oil sands projects under construction as of December 2017.

4.4 Is current and planned pipeline and rail infrastructure sufficient to transport oil to market without the Project?

22. Current and planned pipeline and rail infrastructure are sufficient to transport projected Western Canadian oil supply to market without the Project until at least 2040.

23. At the time of the Project was initially approved in 2016, other new export pipelines were uncertain. The Keystone XL pipeline to the southern U.S. had been cancelled by the Obama Administration, and the Line 3 restoration project to Superior, Wisconsin, had been stalled by regulatory issues in Minnesota. Since then, however, Keystone XL was approved by the Trump Administration in March 2017 (with construction slated to start in 2019 and with an in-service date of 2021),[20] and U.S. portion of Line 3 was approved in June 2018 (it is currently under construction with an in-service date of late 2019). Together these two projects will add 1.2 million barrels per day of export capacity, approximately double that of the Project, to markets in the U.S. mid-west and U.S. Gulf Coast. In addition, Enbridge has indicated it has 0.45 million barrels per day of incremental capacity that it intends to add to its mainline, some of which will be in-service in 2019 (175,000 barrels per day), further increasing export capacity.[21]

24. Table 3 summarizes existing and planned pipeline export capacity in Western Canada along with rail capacity and supply that would be used by domestic refineries. A net practical capacity is also listed, given that pipelines cannot operate at full nameplate capacity nor can refineries. The net capacity is assumed to be 95% of nameplate capacity to allow for outages and maintenance. In the case of the Enbridge mainline, however, net export capacity is reduced by

[20] The recent lower court ruling against Keystone XL in November 2018 will require a revised environmental assessment unless the decision is overturned by an appeal. Given that TransCanada was not planning to start major construction until 2019, it may not significantly delay the planned 2021 in-service date. TransCanada has also indicated that this court decision is manageable and that it remains committed to the project https://business.financialpost.com/commodities/energy/transcanada-open-minded-about-joint-venture-partner-for-10-billion-keystone-xl-pipeline .

[21] Enbridge Inc., August 2018, Investor Community Presentation, slide 24.

a total of 544,000 barrels per day given that some refined products, as well as some U.S. sourced oil from the Bakken field in North Dakota, are carried on it, and the existing Trans Mountain pipeline is reduced by 50,000 barrels per day to allow for shipments of refined petroleum products to B.C. A very modest amount of new refinery capacity is assumed to come on line by 2030 (158,000 barrels per day), which could be from the approved Phases 2 and 3 of the Sturgeon Refinery, of which Phase 1 was completed in 2018, or other projects.

Export capacity from Western Canada (kbd)				
Pipeline	**Nameplate capacity**	**Net capacity (95% also see notes)**	**Nameplate Capacity Source**	**Notes on net capacity**
Existing export pipelines				
Enbridge Mainline	2,851	2,307	CAPP 2018	less US Bakken and refined petroleum products as per CAPP.
Existing Trans Mountain pipeline	300	250	CAPP 2018	less 50 kbd of refined petroleum products as per CAPP
Enbridge Express	280	266	CAPP 2018	
TransCanada Keystone	591	561	CAPP 2018	
Rangeland–Milk River	203	193	AER 2018	
Total 2018 existing capacity	4,226	3,577		
Western refinery receipts and rail capacity				
Refinery consumption	749	712	CAPP 2018	Assume 95% availability
Rail capacity	770	740	CAPP 2018	Assume 95% availability
Grand total 2018 capacity	5,661	5,029		
Capacity under construction or likely to be built				
Line 3 replacement (2019)	370	352	CAPP 2018	
TransCanada Keystone XL (2021)	830	789	CAPP 2018	
Enbridge mainline expansion	450	428	Enbridge 2018	175 kbd 2020; 275 kbd 2022
Scotford refinery Phase 2 and 3 or other refinery additions	158	150	Northwest 2018	Phase 2 79 kbd 2025; Phase 3 79 kbd 2030
Existing plus likely capacity	7,311	6,747		
Proposed Canadian "tidewater" pipelines				
KM Trans Mountain expansion	590	561	CAPP 2018	
Total	7,901	7,308		

Table 3 – Existing, planned, proposed pipeline and rail export capacity, and domestic refinery capacity in Western Canada. Also shown is net capacity allowing for maintenance and outages, as well as other draws on the Enbridge mainline and the existing Trans Mountain pipeline that reduce export capacity. CAPP 2018 refers to CAPP's 2018 forecast.[22] AER2018 refers to an Alberta Energy report.[23] Northwest 2018 refers to Northwest refining.[24] Kbd = thousand barrels per day.

25. Existing and planned pipeline export capacity in Western Canada along with rail capacity and supply that would be used by domestic refineries is approximately 7.3 million barrels per day without the Project, and 7.9 million barrels per day with the Project.

26. Figure 6 illustrates the existing and planned pipeline, rail, and domestic refinery net capacity (see Table 3) in Western Canada through 2040, along with Western Canadian oil supply in the

[22] Canadian Association of Petroleum Producers, 2018 Crude Oil Forecast: MARKETS AND TRANSPORTATION. http://www.capp.ca/~/media/capp/customer-portal/publications/320292src
[23] Alberta Energy Regulator, 2018, Pipelines ST-98, https://www.aer.ca/providing-information/data-and-reports/statistical-reports/pipelines
[24] Northwest Refining, overview of Sturgeon Refinery and phases 2 and 3. http://www.nwrefining.com/the-sturgeon-refinery/

NEB's reference, low price, and technology cases with and without the Alberta 100 Mt oil sands emissions cap.

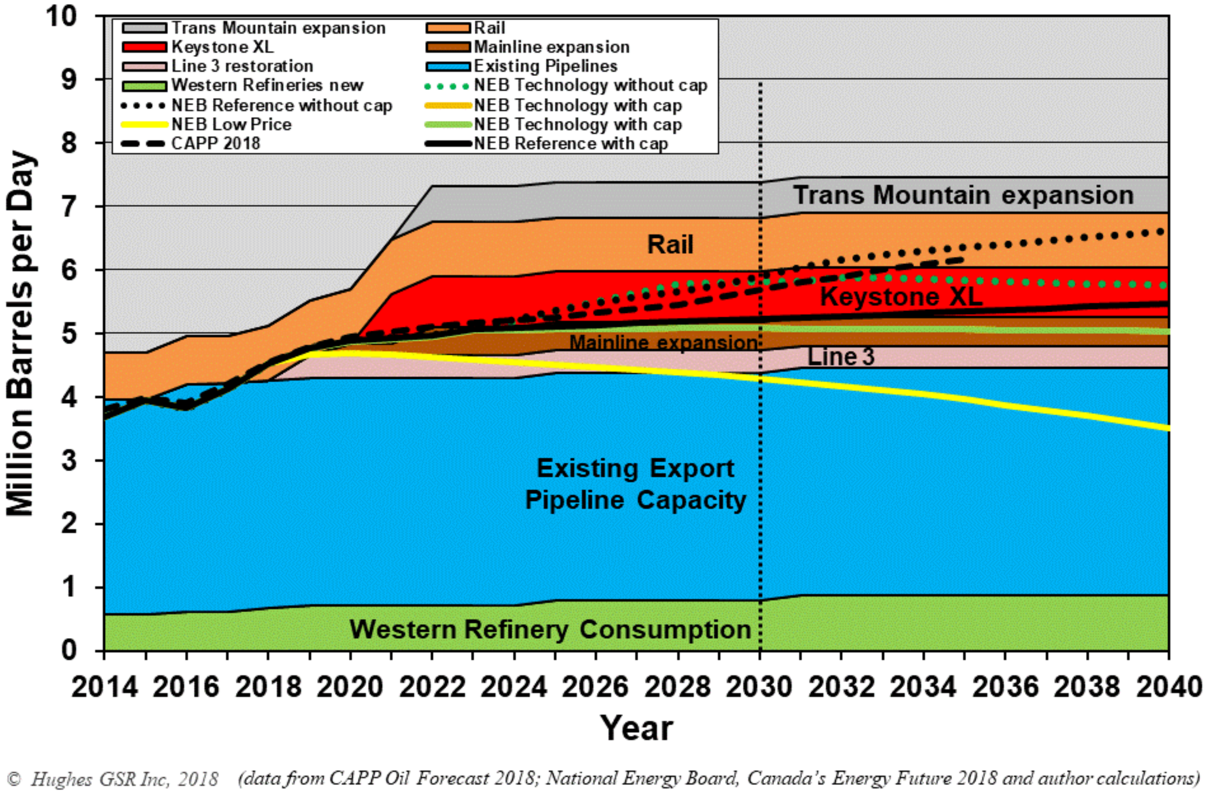


Figure 6 – Existing and planned pipeline, rail and domestic refinery net capacity (see Table 3) showing Western Canadian oil supply in NEB's reference, low price and technology cases with and without the Alberta 100 Mt oil sands emissions cap. Also shown for comparison is CAPP's 2018 supply forecast without the cap.

27. The key takeaway from Figure 6 is that existing and planned pipeline and rail infrastructure without the Project will provide sufficient oil transportation capacity to satisfy transportation needs under the NEB and CAPP 2018 supply cases, both with and without an emissions cap:

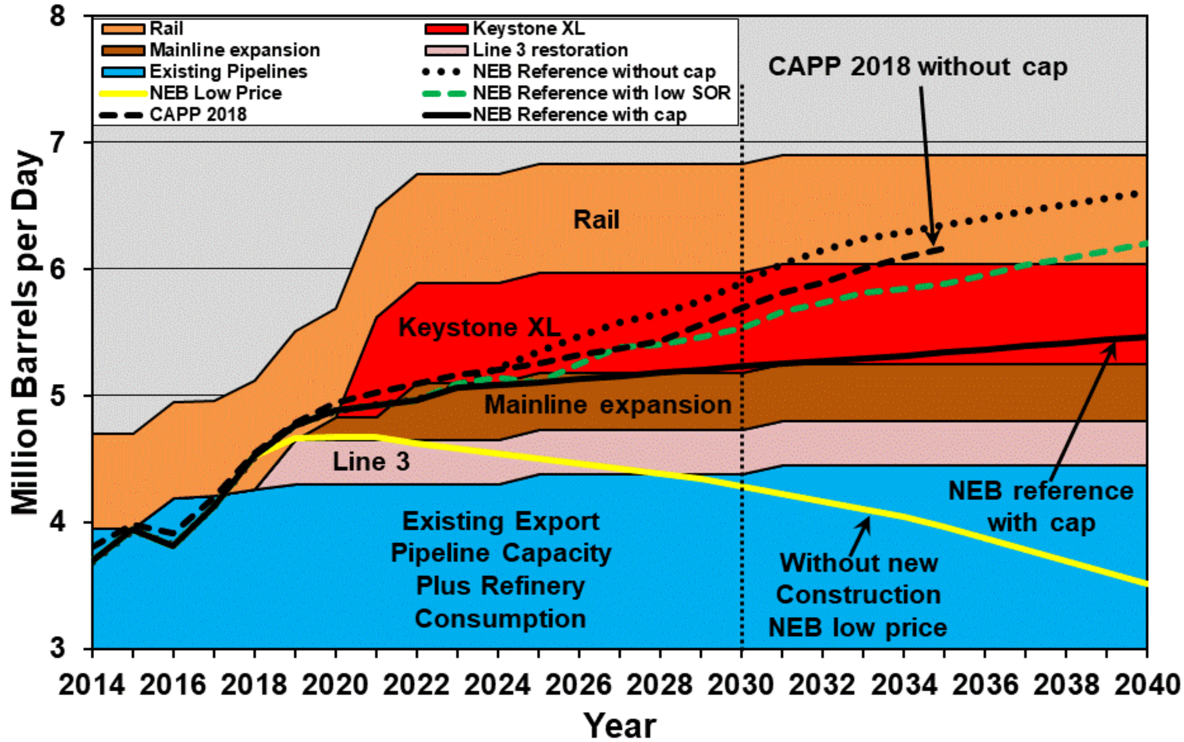
(a) The NEB's reference, low price, and technology cases under the emissions cap can be accommodated largely by Line 3 and the Mainline expansion, with only a minor draw on Keystone XL in the reference case. No rail would be required in any of these cases.

(b) Even without the emissions cap, there will be sufficient pipeline capacity through 2040 to transport oil in the NEB's low price and technology cases without the need for rail or the Project, although the reference case without the cap would require some rail after 2031.

(c) In CAPP's 2018 Western Canadian supply case, some rail would be required after 2033 without the oil sands emissions cap.

28. The most relevant forecasts for Western Canadian supply are the NEB reference and low price cases under the Alberta oil sands emissions cap. The NEB low case corresponds to a scenario in which Canada's climate commitments are more likely to be achieved and new oil sands construction is very limited. Figure 7 illustrates these scenarios at an expanded scale along with production under the emissions cap in the NEB's reference case if the NEB's assumptions of

declining SOR after 2025 illustrated in Figure 2 are achieved. Also shown are the NEB's reference case and CAPP's 2018 Western Canadian supply forecasts without the Alberta oil sands emissions cap.



© Hughes GSR Inc, 2018 (data from CAPP Oil Forecast 2018; National Energy Board, Canada's Energy Future 2018 and author calculations)

Figure 7 – Existing and planned pipeline, rail, and domestic refinery net capacity (see Table 3) showing Western Canadian oil supply in the NEB's reference and low price cases, with and without the Alberta oil sands emissions cap. Also shown are CAPP's 2018 supply forecast without the cap and the NEB reference scenario with the cap assuming the SOR reductions illustrated in Figure 2 are achieved.

29. Figure 7 shows that existing and planned pipeline capacity will provide sufficient oil transportation capacity to satisfy transportation needs for the NEB's reference and low price cases with an emissions cap, without rail or the Project. Moreover, Keystone XL is not needed under the reference case with an emissions cap until after 2033.

30. With improved technology for in situ extraction, as discussed above (see Figure 2), the NEB reference case with the emissions cap would require some rail after 2038. Without the emissions cap, the NEB reference case would require some rail after 2031 and the CAPP 2018 forecast would require some rail after 2033.

31. The NEB low price case could be accommodated with Line 3 and the Mainline expansion alone.

32. Importantly, the Project is not required in any of these scenarios during the examined timelines (i.e. out until 2040).

5.0 WILL THE PROJECT INCREASE THE PRICE PER BARREL OF OIL THAT CANADIAN PRODUCER ARE ABLE TO OBTAIN?

5.1 Comparison of costs of shipping WCSB crude to Asian and U.S. markets on the Project relative to existing and other proposed pipelines

33. Oil is a globally traded commodity; hence its delivered price tends be similar in widely separated markets after adjustments for quality and transportation. The price obtained by the producer depends on transportation costs and quality differences, as well as price discounts due to transportation bottlenecks such as exist now in Western Canada due to pipeline capacity constraints.

34. Trans Mountain set tolls for the Project in 2013.[25] The pipeline tolls were based on an initial cost estimate of $5.4 billion for the Project. Trans Mountain indicated that the fixed rate toll would increase by $0.07 per barrel for each $100 million increase in Project costs from the initial cost estimate.[26] Trans Mountain estimated that Project costs had increased to between $8.4 and $9.3 billion in August 2018 prior to the sale of the Project.[27] The $8.4 billion estimate was predicated on a December 2020 in-service date, which is now unlikely. The subsequent Federal Court of Appeal decision which invalidated the approval of the Project has involved delays which suggests that TD's $9.3 billion estimate, with its December 2021 in-service date, is more realistic.

35. Table 4 illustrates transportation costs (tolls) from Edmonton via the Project to the Westridge Terminal and tanker to south China, versus the pipeline toll from the Hardisty hub in Alberta to the U.S. Gulf Coast and U.S. mid-west. Toll increases due to the escalation of the costs of the Project ($2.10 - $2.73) are added to the original Project tolls, and the toll increase due to the construction cost of Line 3 on the Enbridge mainline ($0.80)[28] are added to tolls from Hardisty to the U.S. mid-west and U.S. Gulf Coast.

36. Given the more likely scenario of a $9.3 billion cost for the construction of the Project, the additional transportation cost for shipping heavy oil to Asia via the Project and tankers compared to the U.S. Gulf Coast is $US2.68 to $US3.08 per barrel depending on the volume shipped and the length of the shipping contract. The transportation toll difference to send heavy oil to Asia compared to the U.S. mid-west is estimated at between $US5.63 and $US6.03 per barrel.

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[25] Trans Mountain, 2013, B15-24 - Revised Jan 10 2013 APPENDIX 9 Final form of the FSA - TSA Schedules - A3E7D5 https://apps.neb-one.gc.ca/REGDOCS/File/Download/901941

[26] Trans Mountain, 2013, B15-22 - Appendix_7_Final_form_of_the_FSA - A3E7D3, see page 10, https://apps.neb-one.gc.ca/REGDOCS/File/Download/902023

[27] Trans Mountain Canada Limited, July 27, 2018, Notice of special meeting of shareholders to be held on Thursday, August 30, 2018.

[28] Enbridge Energy, Limited Partnership. Certificate of Need Application, MPUC Docket No. PL-9/CN-14-916.

Heavy Oil Tolls for Various Transportation Routes	Toll with increase due to $3.0 billion cost escalation to $8.4 billion final cost $US2018	Toll with increase due to $3.9 billion cost escalation to $9.3 billion final cost $US2018
Edmonton to Westridge Terminal		
HIGH CASE Trans Mountain (2013) firm service 15 year committed heavy oil toll for less than 75kbd committed volumes ($5.29 CAN2013)	$6.23	$6.79
LOW CASE Trans Mountain (2013) firm service 20 year committed heavy oil toll for more than 75kbd committed volumes ($4.80 CAN2013)	$5.83	$6.39
Tanker Voyage Westridge to South China		
Muse-Stancil (2015) Cold Lake Blend Heavy 2018 (Table A-3) ($4.17 in $US2015)	$4.39	$4.39
Total Toll Edmonton to South China		
HIGH CASE Trans Mountain (2013) firm service 15 year committed heavy oil toll for less than 75kbd committed volumes	$10.62	$11.18
LOW CASE Trans Mountain (2013) firm service 20 year committed heavy oil toll for more than 75kbd committed volumes	$10.22	$10.78
Hardisty to Chicago		
CAPP 2018	$4.35	$4.35
Toll increase on Enbridge mainline due to expansions through 2020	$0.80	$0.80
Total in 2020	$5.15	$5.15
Hardisty to U.S. Gulf Coast		
CAPP 2018 (Enbridge/Seaway) 15 year, 50 kbd committed volumes	$7.30	$7.30
Toll increase on Enbridge mainline due to expansions through 2020	$0.80	$0.80
Total in 2020	$8.10	$8.10
Toll price penalty selling to Asia		
To Chicago HIGH CASE Trans Mountain (2013) firm service 15 year committed heavy oil toll for less than 75kbd committed volumes	$5.47	$6.03
To Chicago LOW CASE Trans Mountain (2013) firm service 20 year committed heavy oil toll for more than 75kbd committed volumes	$5.07	$5.63
To Far East HIGH CASE Trans Mountain (2013) firm service 15 year committed heavy oil toll for less than 75kbd committed volumes	$2.52	$3.08
To Far East LOW CASE Trans Mountain (2013) firm service 20 year committed heavy oil toll for more than 75kbd committed volumes	$2.12	$2.68

Table 4 – Tolls for heavy oil for the Project to Asia versus tolls to the U.S. mid-west and U.S. Gulf Coast outlining the price differential due to transportation costs between U.S. and Asian exports. Tolls were adjusted based on the $5.4 billion initial cost estimate given Trans Mountain's toll increase of $CAN0.07 increase per $100 million increase in the cost of the Project.

5.2 Comparison of price for products shipped on the Project to Asia and the U.S. with price for products shipped on existing and proposed pipelines from 2018-2030

37. The Mexican Maya benchmark is a heavy oil equivalent to Canada's Western Canadian Select (WCS) benchmark, and is traded both on the U.S. Gulf Coast and in the Far East. Table 5 documents the price in both markets by month over the past year and by year from 2013-2017. **Maya delivered to the U.S. Gulf Coast has sold at an annual average price premium of $3.46 per barrel compared to Maya delivered to the Far East over the past 6 years**.

Date	Maya Far East	Maya USGC	Difference USGC-Far East
2013	$96.88	$96.82	-$0.06
2014	$78.02	$85.77	$7.75
2015	$36.07	$43.45	$7.38
2016	$34.63	$36.20	$1.57
2017	$46.23	$46.88	$0.65
11/06/17	$53.37	$53.72	$0.35
12/01/17	$52.89	$53.54	$0.65
01/02/18	$54.90	$54.36	-$0.55
02/01/18	$58.36	$58.41	$0.05
03/01/18	$52.93	$54.05	$1.12
04/02/18	$55.02	$55.57	$0.55
05/01/18	$59.48	$60.43	$0.95
06/01/18	$65.54	$65.39	-$0.14
07/02/18	$65.60	$68.78	$3.19
08/01/18	$65.53	$68.23	$2.70
09/04/18	$67.70	$69.98	$2.28
10/01/18	$72.61	$74.53	$1.92
11/01/18	$68.78	$69.18	$0.40
Average U.S. Gulf Coast Premium 2018			$1.04
Average U.S. Gulf Coast Premium 2013-2018			$3.06

Table 5 – Price of Mexican Maya delivered to the U.S. Gulf Coast compared to Maya delivered to the Far East in Asia by annual average price for the years 2013 through 2017[29] and monthly price for 2018.[30]

38. Refineries on the U.S. Gulf Coast have made substantial investments in complex coking and cracking technology in order to optimally process heavy, sour crude oil which has mainly been sourced from suppliers in Mexico and Venezuela. These refineries are unsuited for the light, sweet crude oil produced from tight oil deposits in the U.S., hence they remain significant importers of heavy oil (growing production of light, sweet crude oil is increasingly exported to other markets with less complex refining capacity). Although Canada has increased its access to the U.S. Gulf Coast market, a current, temporary lack of pipeline capacity has constrained its

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[29] PEMEX Statistical Yearbook 2017 http://www.pemex.com/en/investors/publications/Documents/STATISTICAL-YEARBOOK-2017.pdf

[30] OILPRICE.COM, Oil price charts and data retrieved November 6 2018, https://oilprice.com/oil-price-charts

penetration there. The construction of Line 3 and Keystone XL will allow far greater access to the U.S. Gulf Coast and the premium prices for heavy, sour crude oil found there.

39. Figure 8 illustrates imports of heavy, sour crude oil to U.S. Gulf coast refineries from 2010 to 2018 by country. Capacity exists to handle about 2.4 million barrels per day but supply has decreased to just under 2 million barrels per day primarily due to decreases in production from traditional suppliers in Venezuela and Mexico, imports from which have declined by 40% since 2010. Mexican and Venezuela oil production peaked in 2004 and 1998, respectively, and net exports from each have declined 84% and 46%, respectively, since peaking.[31] Imports from these countries will continue to decline as production falls further. Meanwhile, Canada's exports to the U.S. Gulf Coast have increased 318% since 2010, and there is opportunity to grow exports much more once Line 3 and Keystone XL are completed. Canadian heavy oil exports to the U.S. Gulf Coast have been capturing premium prices.[32]

[31] BP Statistical Review of World Energy 2018.

[32] Calgary Herald October 25, 2018, What discount? Gulf Coast paying premium prices for Canadian oil – but only 450,000 bpd make it there, https://calgaryherald.com/commodities/energy/what-discount-gulf-coast-paying-premium-prices-for-canadian-oil-but-only-450000-bpd-make-it-there/wcm/71f49e90-bfb7-40f8-9053-75167c8c696e

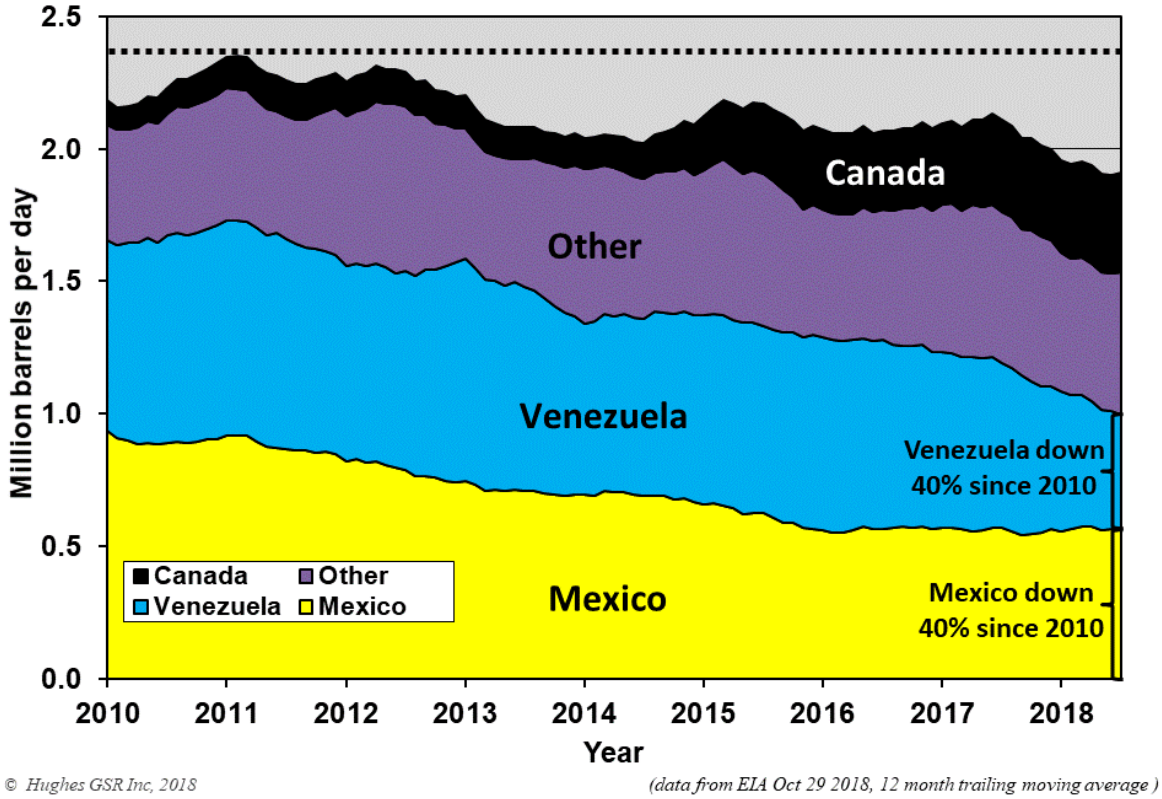

Figure 8 – Imports of heavy, sour crude oil to U.S. Gulf Coast refineries (PADD 3) from 2010 to 2018 (12 month trailing moving average).[33] Imports from traditional suppliers in Mexico and Venezuela have declined 40% over this period, whereas imports from Canada have increased 318%.

40. Completion of the Line 3 and Keystone XL pipelines will allow much greater access to premium prices for heavy oil on the U.S. Gulf Coast.

[33] U.S. Energy Information Administration, accessed October 29, 2018 at https://www.eia.gov/petroleum/imports/browser/?src=home-b1#/?d=60&e=201807&f=m&g=1&s=200901&sid=PET_IMPORTS.WORLD-RP_2-1.M~PET_IMPORTS.WORLD-RP_3-1.M&v=l&vs=PET_IMPORTS.CTY_CA-RP_2-1.M~PET_IMPORTS.CTY_CA-RP_3-1.M~PET_IMPORTS.CTY_MX-RP_2-1.M~PET_IMPORTS.CTY_MX-RP_3-1.M~PET_IMPORTS.CTY_VE-RP_2-1.M~PET_IMPORTS.CTY_VE-RP_3-1.M~PET_IMPORTS.WORLD-RP_2-1.M~PET_IMPORTS.WORLD-RP_3-1.M

5.3 Will WCSB producers shipping on the Project receive "netbacks" relative to existing and proposed pipelines from 2018-2030?

41. Trans Mountain's consultant, Muse Stancil, used the proprietary "Muse Crude Oil Market Optimization Model" to project an average $1.78 per barrel increase in the price of WCS over the 2018 to 2038 period (and higher for some other oil types) due to building the Project.[34] To support this assertion, Muse Stancil projected that although deliveries of Canadian oil to most markets would be relatively unchanged, deliveries to the U.S. Gulf Coast would be significantly reduced and Asian deliveries significantly increased as shown in Figure 9.

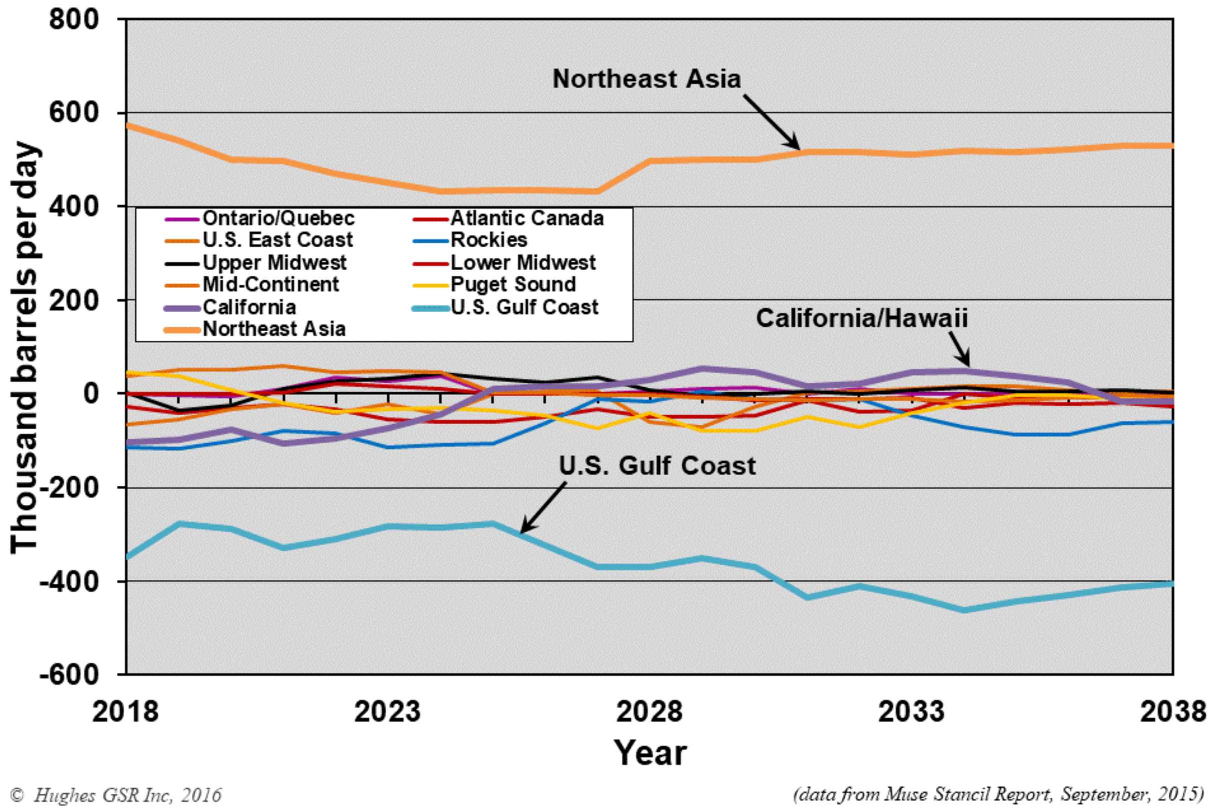

Figure 9 – Changes in destination of light and heavy oil deliveries from 2018 to 2038 as a result of the construction of the Project according to Trans Mountain's consultant Muse Stancil.[35]

42. In its report for Trans Mountain, Muse Stancil estimated that the Project will provide a benefit of $CAN73.5 billion for Canadian producers over 21 years. This estimate is based on the incorrect assumption that if the Project is not built, WCSB oil would have to be shipped by rail. But as shown in my report, Muse Stancil's analysis is outdated and no longer relevant. New pipeline capacity under development will provide export capacity, without the use of rail, to higher value markets than the Project. Consequently, Trans Mountain's assumption that rail is the alternative to the Project is incorrect. Furthermore, since the completion of Trans Mountain's report on project benefits by Muse Stancil, the costs of shipping on the Project have escalated significantly. As my analysis in Table 4 shows, transportation costs are $US2.68 to $US3.08 per barrel higher to Asian markets via the Project than to higher value markets on the U.S. Gulf Coast via

[34] Muse-Stancil, September 2015, Market prospects and benefits analysis of the Trans Mountain Expansion Project for Trans Mountain Pipeline (ULC), Table A-16.
[35] Ibid. This figure compares the 'Trans Mountain Expansion Scenario' to the 'Base Scenario' for Western Canadian light-, medium- and heavy-oil in Tables A-10 through A-13 of the report.

alternative pipeline capacity now under development. Hence, there could now be a net cost to Canadian producers if oil is shipped on the Project relative to the other pipeline options.

43. Based on the above analysis of transportation costs and price in Asian and U.S. Gulf Coast markets, the Project will yield substantial losses for producers given the availability of Line 3, Keystone XL and Enbridge Mainline expansions. The pipeline/tanker toll differential to Asia compared to the U.S. Gulf Coast translates into a loss of $CAN14.0 to $CAN16.1 billion over a 21-year operating period for the Project.[36] If the premium for heavy oil on the U.S. Gulf Coast compared to the Far East observed over the past six years persists, losses to producers shipping on the Project to Asia would be significantly higher (each $US1.00 premium on the US Gulf Coast versus Asian markets confers an additional $CAN5.2 billion loss selling oil to Asia via the Project over a 21-year project life - the U.S. Gulf Coast premium has averaged $US3.06 over the past six years).[37]

44. In summary, the Project will very likely result in negative returns for producers compared to positive netbacks with the completion of other pipeline export projects between 2019 and 2021. The benefits of the Project have been vastly overstated when in reality the Project will likely provide negative financial returns for Canadian producers.

6.0 SUMMARY OF FINDINGS, OPINIONS AND CONCLUSIONS

45. New export pipeline developments since the approval of the Project have rendered it unnecessary and surplus to Canadian needs. These new developments include the Line 3 pipeline expansion slated for completion in late 2019 and the Keystone XL pipeline slated for completion in 2021. These projects will add 1.2 million barrels per day of export capacity from Western Canada. An additional 0.45 million barrels per day of increased export capacity is also available from the expansion of the existing Enbridge Mainline. Together these projects will add 1.65 million barrels per day of new pipeline export capacity or nearly three times that of the Project.

46. Existing and proposed pipeline expansions (Line 3, Enbridge mainline and Keystone XL) will provide sufficient pipeline capacity to meet WCSB oil transportation needs until 2031 based on the NEB reference case production oil forecast and until 2033 based on the CAPP supply forecast, without using rail and without the Project.

47. Meeting Alberta's 100 Mt cap on oil sands emissions will constrain Western Canadian oil production growth in all NEB scenarios except the low price case, which doesn't reach the annual 100 Mt emissions limit. Under the NEB low price and NEB reference case with Alberta's GHG emissions cap, existing and proposed pipeline expansions (Enbridge Line 3 and mainline expansions) are sufficient to meet WCSB transportation needs to 2032, without building the Project or Keystone XL and without using rail.

48. Projected growth in emissions from oil and gas production in NEB's reference case, even under Alberta's oil sands emissions cap, will make meeting Canada's Paris Agreement emissions reduction targets extremely difficult. Even with the cap, emissions outside of the oil and gas sector would have to decrease 48% from 2016 levels by 2030 and 88% by 2040.

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[36] The loss is calculated by converting into Canadian dollars the differential between oil shipped to the U.S. Gulf Coast and oil shipped via TMX to Asia at the Muse and Trans Mountain toll rates assuming TMX would run at 95% of its nameplate capacity over a 21-year project life.

[37] Trans Mountain submission of Muse-Stancil report, September 2015, Market prospects and benefits analysis of the Trans Mountain Expansion Project for Trans Mountain Pipeline (ULC). See Table 2.

49. There is no ‘price premium’ to be had in Asia compared to deliveries to the U.S. Gulf Coast. New pipeline developments will eliminate the current high WCS-WTI differential before the earliest Project completion date of December 2021. Heavy, sour crude oil, equivalent to WCS, has been trading on the U.S. Gulf Coast at an average premium of $US1.04 per barrel compared to Asian deliveries over the past year, and an average premium of $US3.06 per barrel over the past six years.

50. The U.S. Gulf Coast contains the world’s largest concentration of complex refineries able to optimally refine heavy oil. It will therefore continue to be a significant importer of heavy oil given that most of the increase in U.S. domestic production is light sweet crude that is increasingly exported to other countries. Canada’s heavy oil is a good fit, especially given the decline in production and imports from traditional heavy oil suppliers in Mexico and Venezuela. New pipeline export capacity under development will provide much greater access to this market.

51. Transportation costs to Asia via the Project and tanker are also higher than transportation costs to complex refineries in the U.S. mid-west and on the U.S. Gulf Coast. Pipeline/tanker tolls on the Project to Asia will be $US2.68 to $US3.08 per barrel higher than tolls to the U.S. Gulf Coast.

52. Higher transportation costs to Asia compared to shipping to the U.S. Gulf Coast on existing and new pipeline capacity mean that the Project will cost Canadian producers approximately $CAN14 to $CAN16.1 billion over the 21-year operating period assumed by Trans Mountain. The claim by Trans Mountain that the Project will provide Canadian producers with a benefit of $CAN 73.5 billion over 21 years is without merit.

APPENDIX 1

CURRICULUM VITAE

John David Hughes

Overview

David Hughes is an earth scientist that has studied the energy resources of Canada and the U.S. for more than four decades, including 32 years with the Geological Survey of Canada as a scientist and research manager. He is president of Global Sustainability Research Inc., a consultancy that has analyzed the geological fundamentals and production potential of unconventional oil and gas plays across Canada and the U.S. He has published and lectured widely on energy and sustainability issues in North America and internationally. He is also a Fellow of Post Carbon Institute, a Board member of Physicians, Scientists and Engineers for Healthy Energy and a Research Associate with the Canadian Centre for Policy Alternatives.

Education:

First Class Honours Bachelor of Science in Geology, 1972, University of Alberta;

Master of Science in Geology, 1975, University of Alberta

Experience:

2008-present: President, Global Sustainability Research Inc.

President of Global Sustainability Research Inc., a consultancy conducting research on global and North American energy and sustainability issues. A key focus has been on unconventional hydrocarbons as well as on promoting awareness of energy issues based on in-depth analyses of available data on global, North American and Canadian energy consumption and production trends and forecasts. In this regard presentations have been given at more than 200 North American and international venues over the past several years. Findings have also been released through reports, publications, blog posts and other media.

Clients have included oil and gas companies, environmental NGOs and think tanks, including Imperial Oil, ForestEthics, Post Carbon Institute, Council of Canadians, Canadian Centre for Policy Alternatives, Cornell University and others. Testimony as an expert witness has also been provided on energy issues in several cases.

1976-2008: Scientist and Research Manager, Geological Survey of Canada, Department of Natural Resources, Government of Canada

Responsibilities included:

- Development and management of Canada’s National Coal Inventory, a system for assessing the resource potential of Canada’s coal resources and well as the economic and environmental implications of their use.

- Development and management of a National assessment of unconventional energy resources in Canada including coalbed methane and shale gas.

- Management of joint industry-government projects on the assessment of the potential of deep unmineable coal seams for carbon capture and storage in western Canada and the Maritimes.

- Management of joint projects with the private sector that saw the development of Canada's first large scale production of coalbed methane in Canada in the late 1990s.

- Management of a multi-disciplinary team of scientists and technicians as Head, Coal Subdivision.

- Research, update and dissemination of an evolving analysis of global and North American energy production, consumption and sustainability issues in a Canadian context.

Research findings have been released through scientific papers, industrial reports, book chapters, oral presentations, internet postings and articles in the media.

2000-2008: Team Leader, Unconventional Gas, Canadian Gas Potential Committee

Team Leader, Unconventional Gas, for the Canadian Gas Potential Committee, which is a volunteer organization of senior petroleum geologists and explorationists. It publishes an authoritative assessment of Canada's natural gas potential on a 4-5 year timeframe. Responsibilities included management of the compilation and publication of two national assessments of Canada's unconventional natural gas potential which were published in 2001 and 2006.

1973-1976: Chief Geologist, Consolidation Coal Company of Canada

Management of a geological team working in conjunction with engineering staff on coal properties in Alberta and B.C. Design and management of drilling programs in southwest and central Alberta.

<u>Recent Publications</u>

2018: Hughes, J.D. Canada's Energy Outlook: Current realities and implications for a carbon-constrained future, Canadian Centre for Policy Alternatives, 180 p.

2018: Hughes, J.D., Shale Reality Check: Drilling into the U.S. Government's Rosy Projections for Shale Gas & Tight Oil Production Through 2050, 171 p.

2017: Hughes, J.D., Will the Trans Mountain Pipeline and Tidewater Access Boost Prices and Save Canada's Oil Industry? Canadian Centre for Policy Alternatives, 42 p.

2016: Hughes, J.D, 2016 Shale Gas Reality Check: Revisiting the U.S. Department of Energy Play-by-Play Forecasts through 2040, Post Carbon Institute, 39 p.

2016: Hughes, J.D, 2016 Tight Oil Reality Check: Revisiting the U.S. Department of Energy Play-by-Play Forecasts through 2040, Post Carbon Institute, 33 p.

2016: Hughes, J.D, Can Canada Expand Oil and Gas Production, Build Pipelines and Keep Its Climate Change Commitments?, Canadian Centre for Policy alternatives, 37 p.

2015: Hughes, J.D, Bakken Reality Check: The Nation's Number Two Tight Oil Play after a year of low prices, Post Carbon Institute, 18 p.

2015: Hughes, J.D, Tight Oil Reality Check: Revisiting the U.S. Department of Energy play-by-play forecasts through 2040 from Annual Energy Outlook 2015, Post Carbon Institute, 17 p.

2015: Hughes, J.D, Shale Gas Reality Check: Revisiting the U.S. Department of Energy play-by-play forecasts through 2040 from Annual Energy Outlook 2015, Post Carbon Institute, 17 p.

2015: Hughes, J.D., A Clear View of B.C. LNG, Canadian Centre for Policy Alternatives, 49 p.

2014: Hughes, J.D, The Geology and Sustainability of Shale. *In* Finkel, ML (ed). The Human and Environmental Impact of Fracking: How Fracturing Shale for Gas Affects Us and Our World. Santa Barbara, CA: Praeger Press. 2015. pp. 195-206.

2014: Hughes, J.D., Drilling Deeper: A Reality Check on U.S. Government Forecasts for a Lasting Tight Oil & Shale Gas Boom, Post Carbon Institute, 315 p.

2014: Hughes, J.D., B.C. LNG Reality Check, Watershed Sentinel, 8 p.

2013: Hughes, J.D., Drilling California: A Reality Check on the Monterey Shale, Physicians, Scientists and Engineers for Healthy Energy, and Post Carbon Institute, 48 p.

2013: Hughes, J.D., A Reality Check on the Shale Revolution, Nature, v. 494, p. 307-308.

2013: Hughes, J.D., Drill Baby Drill: Can Unconventional Fuels usher in a new Era of Energy Abundance?, Post Carbon Institute, 166 p.

Older publications available on request.

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403 276-3056

250-830-3662

APPENDIX 2

CERTIFICATE OF EXPERT'S DUTY

I, David Hughes of British Columbia, Canada have been engaged on behalf of the Tsleil-Waututh Nation, to provide evidence in relation to Trans Mountain Pipeline ULC Application for the Trans Mountain Expansion Project, National Energy Board reconsideration of aspects of its Recommendation Report as directed by Order in Council P.C. 2018-1177 currently before the National Energy Board.

In providing evidence in relation to the above-noted proceeding, I acknowledge that it is my duty to provide evidence as follows:

1. to provide evidence that is fair, objective, and non-partisan;

2. to provide evidence that is related only to matters within my area of expertise; and

3. to provide such additional assistance as the tribunal may reasonably require to determine a matter in issue.

I acknowledge that my duty is to assist the tribunal, not act as an advocate for any particular party. This duty to the tribunal prevails over any obligation I may owe any other party, including the parties on whose behalf I am engaged.

Date: 5 December, 2018 Signature: