Reassessment of Need for the Trans Mountain Pipeline Expansion Project

Production forecasts, economics and environmental considerations

By J. David Hughes

OCTOBER 2020

CCPA
CANADIAN CENTRE for POLICY ALTERNATIVES
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J. DAVID HUGHES is an earth scientist who has studied the energy resources of Canada for more than four decades, including 32 years with the Geological Survey of Canada as a scientist and research manager. He developed the National Coal Inventory to determine the availability and environmental constraints associated with Canada's coal resources. As Team Leader for Unconventional Gas on the Canadian Gas Potential Committee, he coordinated the publication of a comprehensive assessment of Canada's unconventional natural gas potential.

Over the past two decades, Hughes has researched, published and lectured widely on global energy and sustainability issues in North America and internationally. In his work for the Canadian Centre for Policy Alternatives, Hughes authored *A Clear View of BC LNG* in 2015, which examined the issues surrounding a proposed massive scale-up of shale gas production in British Columbia for LNG export, *Can Canada increase oil and gas production, build pipelines and meet its climate commitments?* in 2016, which examined the issues surrounding climate change and the Trans Mountain pipeline expansion (now updated in this paper), *Canada's Energy Outlook: Current realities and implications for a carbon-constrained future* in 2018, and *BC's Carbon Conundrum: Why LNG exports doom emissions-reduction targets and compromise Canada's long-term energy security* earlier in 2020. He has also authored multiple reports on unconventional oil and gas development in the United States, consulted for the private sector on unconventional oil and gas, and served as an expert witness on hearings for energy projects in the US and Canada.

Hughes is president of Global Sustainability Research, a consultancy dedicated to research on energy and sustainability issues. He is also a board member of Physicians, Scientists & Engineers for Healthy Energy (PSE Healthy Energy) and is a Fellow of Post Carbon Institute. His work has been featured in *Nature*, *Canadian Business*, *Bloomberg* and *USA Today*, as well as other popular press, radio, and television.

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Summary

There have been significant new developments that bear on the need for TMX since the government purchased the project in 2018 and approved it for the second time in 2019.

CANADA'S ACQUISITION OF KINDER MORGAN'S TRANS MOUNTAIN PIPELINE and expansion project (TMX), and its subsequent efforts to begin construction, have been fraught with delays, opposition and court challenges. This report assesses the latest data on the need for the project and its likely impact on Canadian producers and commitments under international climate agreements.

There have been significant new developments that bear on the need for TMX since the government purchased the project in 2018 and approved it for the second time in 2019. These include:

- Announced expansions and optimizations of existing pipelines that will increase export capacity over the next two to three years, including the Enbridge mainline, and the Aurora-Rangeland, Keystone and Express pipelines.
- The reversal of the Southern Lights pipeline for export use in 2023.
- The likely completion of the Line 3 expansion project in 2021.
- The release of new production forecasts since June, 2019, by the Canada Energy Regulator (CER, formerly the National Energy Board), Alberta Energy Regulator (AER), Canadian Association of Petroleum Producers (CAPP) and International Energy Agency (IEA).
- The release of the latest update of Alberta's Oil Sands Emissions Limit Act in January 2020.
- The release of Canada's 2020 emissions report by economic sector which allows an updated assessment of future emissions from the oil and gas sector and compliance with Alberta's 2020 Oil Sands Emissions Limit Act.
- The increase in the cost of the TMX project from $7.4 billion when it was purchased in 2018 to $12.6 billion in February 2020, which will significantly increase shipping costs for Canadian producers selling oil to Asia compared to US exports.
- The COVID-19 pandemic of 2020 which has resulted in an unprecedented decline in the demand for oil and is likely to reduce demand in the longer term.

Key conclusions of this report are as follows:

1. Emissions from the oil and gas sector alone are on track to exceed Canada's emissions reduction target in 2050 by 81 per cent—even with a 100 megatonne (Mt) per year cap on oil sands emissions (as evidenced from the latest CER oil and gas production forecast, coupled with the latest Environment Canada emissions report). Without the cap, emissions from the oil and gas sector would exceed this target by 101 per cent.

2. The increase in oil production forecast by CER (with an oil sands emissions cap), AER, CAPP and IEA can easily be accommodated for the next decade with existing pipelines, including announced optimizations and the Line 3 expansion, without rail or the TMX and Keystone XL pipelines. These forecasts, however, substantially overstate likely production increases as they do not account for the impact of demand reduction resulting from the COVID-19 pandemic or the need to reduce emissions from oil and gas production to meet Canada's emissions reduction targets.
3. There is no price premium to be had selling Canadian heavy oil to Asia. In fact, based on Pemex sales of Maya heavy oil (comparable to Canada's Western Canada Select heavy oil benchmark) over the past six years, cargos bound for the Far East sold at an average discount of $4.27 per barrel compared to cargos bound for the US. (The higher price paid for heavy oil in the US reflects the fact that the US has more than half of the world's refineries equipped to process heavy oil.)
4. Transportation costs to Asia from Alberta are also higher than to the US Midwest or Gulf Coast. Transport costs to south China are between US$1.88 to US$3.52 per barrel higher than to the US Gulf Coast, and from US$5.90 to US$7.92 per barrel higher than to the US Midwest.
5. Thus, the narrative that the Trans Mountain Expansion project will lead to increased netbacks[1] for Canadian producers is not supported by the evidence. The discount from selling Canadian heavy oil to Asia, coupled with higher transportation costs, will lead to a reduction in netbacks for Canadian producers, compared to the US, of US$4 to US$6 per barrel or more.
6. Therefore, the government's claim that TMX must be built in order to provide increased revenue to Canadian oil producers and $500 million per year to reduce emissions must be viewed with extreme skepticism. An expenditure of $12.6 billion tax dollars on a project that will likely reduce revenues for Canadian producers would certainly be better spent directly on reducing emissions.

The government's claim that TMX must be built in order to provide increased revenue to Canadian oil producers and $500 million per year to reduce emissions must be viewed with extreme skepticism.

Canada's emissions reduction policies have so far proven to be ineffective at the scale required. Although Canada has committed to a 30 per cent reduction of emissions by 2030 (from 2005 levels), emissions were down only 0.14 per cent by 2018. Emissions in Alberta, where the oil to fill TMX would be produced, have increased by 17.5 per cent since 2005.

The $12.6 billion the government plans to spend on the construction of TMX is counterproductive, as it is unlikely to increase the profits of Canadian producers or result in a revenue stream that will both cover construction costs and provide additional funds to reduce emissions in a meaningful timeframe. If anything, TMX will exacerbate the emissions problem by incentivizing additional production growth while diverting funds that could otherwise be spent on actual emissions reduction. TMX will also increase the risk of oil spills along its route and in the marine environment. Canada urgently requires a viable strategy that will effectively address future energy security needs, environmental objectives, and emissions reduction targets.

1 "Netbacks" refers to profit after covering production, marketing and transportation costs.

Introduction

At the heart of the rationale behind TMX is the notion that Canada will capture higher prices for its oil in Asia, compared with the US market, where virtually all Canadian oil exports are sold.

THE TRANS MOUNTAIN PIPELINE EXPANSION (TMX) PROJECT was first proposed by Kinder Morgan in 2012, and was approved by the National Energy Board (NEB) and federal government in 2016. The project became a lightning rod for mass protests and arrests, and in early 2018 Kinder Morgan suspended non-essential spending — the federal government subsequently purchased the existing Trans Mountain pipeline and related infrastructure from Kinder Morgan for $4.5 billion in mid-2018 in order to ensure the expansion project would proceed. In August 2018, the Federal Court of Appeal overturned the federal government's approval of the project, and a second round of environmental assessment and consultation was commenced, which culminated in the federal government approving TMX a second time in June 2019.[2] In the meantime, the cost of the expansion project increased from an initial estimate of $5.4 billion in 2013 to the most recent estimate of $12.6 billion made in February 2020.[3]

In parallel with the evolution of the TMX project, the federal government signed the Paris Agreement in 2016, which committed Canada to a 30 per cent reduction in emissions from 2005 levels by 2030.[4] In addition, the federal government has committed to achieving net-zero emissions by 2050, stating, "Canada will develop a plan to achieve net-zero emissions by 2050 and will set legally-binding, five-year emissions reduction milestones."[5] The government justified the apparent conflict between expanding oil production infrastructure and reducing emissions by claiming TMX would generate $500 million in annual revenue, which would be spent on reducing emissions.[6]

At the heart of the rationale behind TMX is the notion that Canada will capture higher prices for its oil in Asia, compared with the US market, where virtually all Canadian oil exports are sold.

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2 Canadian Press, "Timeline: Key Dates in the History of the Trans Mountain Pipeline," *CBC News*, October 3, 2018, updated June 18, 2019, https://www.cbc.ca/news/canada/calgary/timeline-key-dates-history-trans-mountain-pipeline-1.4849370.

3 Vassy Kapelos and John Paul Tasker, "Cost of Trans Mountain Expansion Soars to $12.6B," *CBC News*, February 7, 2020, https://www.cbc.ca/news/politics/vassy-trans-mountain-pipeline-1.5455387.

4 Catherine Cullen, "Justin Trudeau Signs Paris Climate Treaty at UN, Vows to Harness Renewable Energy," *CBC News*, April 22, 2020, https://www.cbc.ca/news/politics/paris-agreement-trudeau-sign-1.3547822.

5 Environment and Climate Change Canada, "Government of Canada Releases Emissions Projections, Showing Progress towards Climate Target," news release, December 20, 2019, https://www.canada.ca/en/environment-climate-change/news/2019/12/government-of-canada-releases-emissions-projections-showing-progress-towards-climate-target.html.

6 Mia Rabson, "Trans Mountain Pipeline Could Fund $500M a Year in Clean Energy Projects," *CBC News*, October 24, 2019, https://www.cbc.ca/news/canada/edmonton/tmx-pipeline-morneau-alberta-1.5333319.

Given that the Canadian government is committed to spending $12.6 billion of its citizens' tax revenue on TMX, and the government's commitments to reducing emissions, this report addresses the following key questions:

- What is the future production outlook from Western Canada for oil exports, considering federal commitments to reduce emissions and Alberta's pledge to cap oil sands emissions at 100 megatonnes (Mt) per year?[7]
- Is TMX needed, given the existing pipeline- and rail-takeaway capacity from Western Canada and new capacity coming online from other projects? (These include announced expansions and optimizations of existing pipelines and the expected completion of the Enbridge Line 3 expansion project in 2021.)
- Will oil exported on TMX capture higher prices in Asia, as claimed by its proponents?

This analysis is based on the most recent oil and gas production forecast from the Canada Energy Regulator (CER),[8] which I will refer to as the "CER forecast," and Canada's 2020 National Inventory Report of emissions by economic sector,[9] referred to as the "NIR emissions report." I also assess production forecasts of the Canadian Association of Petroleum Producers (the "CAPP forecast"),[10] the Alberta Energy Regulator (the "AER forecast")[11] and the International Energy Agency (the "IEA forecast").[12]

7 Province of Alberta, 2020, *Oil Sands Emissions Limit Act, Statutes of Alberta, 2016, Chapter O-7.5 Current as of January 1, 2020*, https://www.qp.alberta.ca/1266.cfm?page=O07p5.cfm&leg_type=Acts&isbncln=9780779814053.

8 Canada Energy Regulator, *Canada's Energy Future 2019: Energy Supply and Demand Projections to 2040* (Ottawa, ON: Canada Energy Regulator, 2019), https://www.cer-rec.gc.ca/en/data-analysis/canada-energy-future/2019/index.html.

9 Environment and Climate Change Canada, *National Inventory Report 1990–2018: Greenhouse Gas Sources and Sinks in Canada* (Ottawa, ON: Environment and Climate Change Canada, 2020), https://unfccc.int/documents/224829.

10 Canadian Association of Petroleum Producers, *2019 Crude Oil Forecast, Markets and Transportation* (Calgary, AB: Canadian Association of Petroleum Producers, 2019), https://www.capp.ca/wp-content/uploads/2019/11/CAPP-2019-Crude-Oil-Markets-and-Transportation-338794-1.pdf.

11 Alberta Energy Regulator, ST98: *Alberta Energy Outlook* (Calgary, AB: Alberta Energy Regulator, 2020), http://www1.aer.ca/ProductCatalogue/32.html.

12 International Energy Agency, *World Energy Outlook 2019* (Paris, France: International Energy Agency, 2019), https://www.iea.org/reports/world-energy-outlook-2019.

Western Canada oil supply

THE LATEST CER FORECAST FOR OIL AND GAS PRODUCTION IN CANADA breaks out production by product, province, production method and producing formation. The latest NIR emissions report breaks down oil production emissions into "conventional," "oil sands mining," "oil sands upgrading" and "oil sands in situ." In the case of oil sands, the effect of Alberta's cap on emissions at 100 Mt per year on future production can be determined using emissions per unit of production (Table 1).

Table 1: Oil sands emissions, production and emissions per barrel from 2005 to 2018

Year	Oil sands emissions (Mt/year)			Oil sands production (kbd)[b]			Oil sands emissions per barrel (kg CO_2e /bbl)[c]		
	Mining	In situ[a]	Upgrading	Mining	In situ	Upgrading	Mining	In situ	Upgrading
2005	9	11	17	626	438	522	39.4	68.7	89.2
2006	11	13	19	760	494	619	39.6	72.1	84.1
2007	12	14	20	784	536	652	41.9	71.6	84.0
2008	11	16	19	721	583	620	41.8	75.2	83.9
2009	12	17	21	825	664	722	39.8	70.2	79.6
2010	12	20	22	857	752	703	38.4	72.8	85.8
2011	12	21	23	893	847	810	36.8	67.9	77.8
2012	14	25	25	932	990	817	41.1	69.2	83.8
2013	15	27	26	976	1,106	835	42.1	66.9	85.3
2014	16	29	25	960	1,263	843	45.7	62.9	81.3
2015	17	33	24	1,161	1,362	850	40.1	66.4	77.3
2016	17	35	22	1,150	1,396	932	40.5	68.7	64.7
2017	18	38	23	1,276	1,546	1,030	38.7	67.3	61.2
2018	18	41	24	1,489	1,555	1,091	33.1	72.2	60.2
Future emissions calculated from the average of 2015–2018							38.1	68.7	65.9

Source: Data from Canada Energy Regulator (see note 8) and Environment and Climate Change Canada (see note 9)

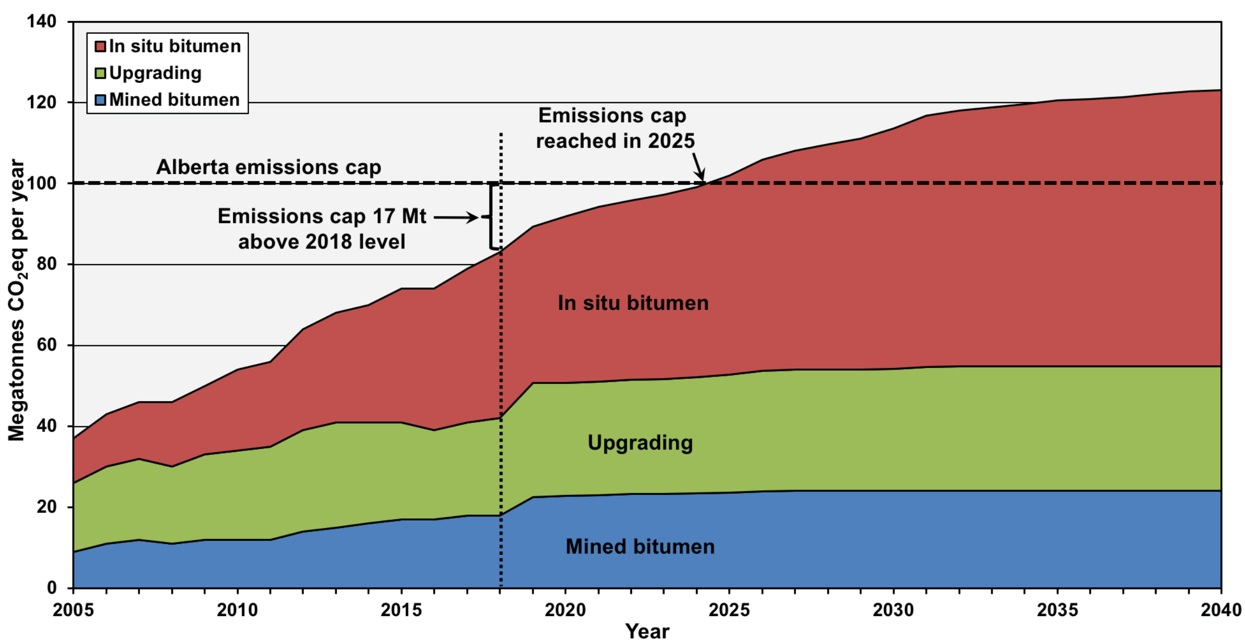
a In situ refers to bitumen produced from wells without mining.

b kbd = thousand barrels per day.

c kg CO_2e/bbl = kilograms of CO_2 equivalent per barrel.

Using an average of the most recent four years for which emissions data are available (Table 1), and the CER forecast of oil sands production, the emissions cap will be reached in 2025 (Figure 1). In 2018, the latest year for which emissions data are available, oil sands emissions still had 17 Mt per year left to grow, before reaching the emissions cap. After 2025, oil sands production would be constrained by the cap — but given Canada's aspirations to achieve net-zero emissions by 2050, reduced oil demand in the future given the coronavirus pandemic, and the aspirations of many other countries to reduce oil consumption and associated emissions, it is questionable if oil sands production will even reach the emissions cap level. (Note that the CER forecast was released before the pandemic.)

Figure 1: Carbon dioxide equivalent emissions from oil sands production, with projected emissions to 2040



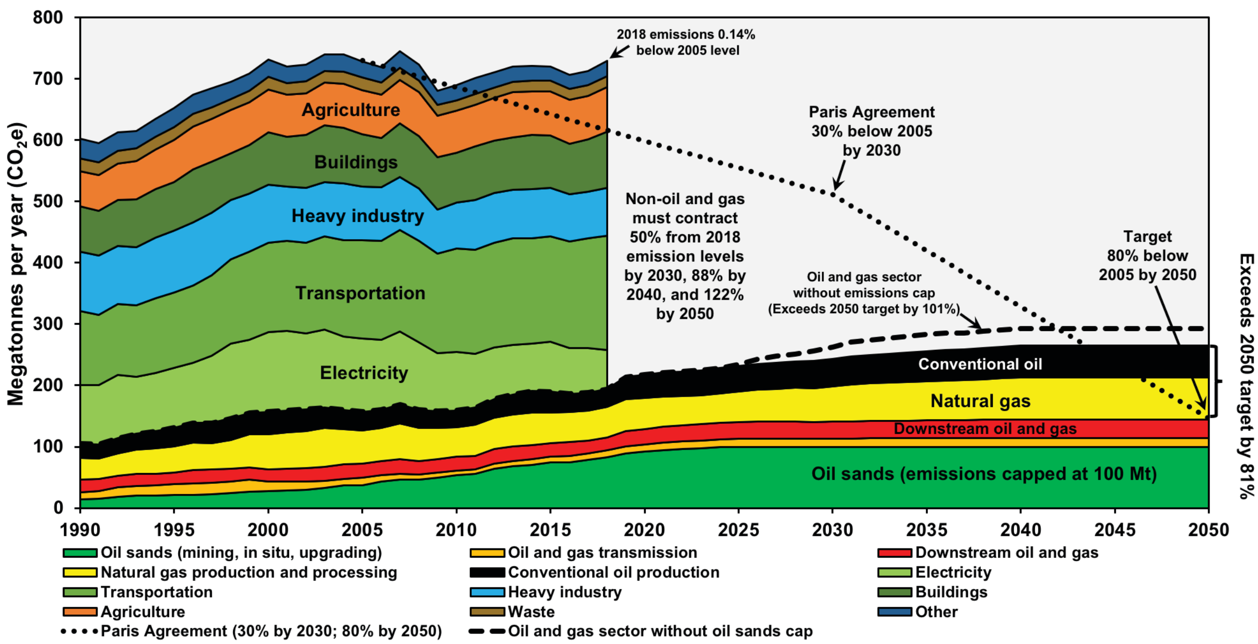
Sources: Data from Environment and Climate Change Canada (see note 9) and Canada Energy Regulator (see note 8).

Figure 2 illustrates Canada's emissions from 1990 through 2018 by economic sector based on the NIR emissions report. The figure also shows projected emissions from the oil and gas sector through 2040 based on the CER forecast (using the 2015–2018 average emissions per unit of production). Emissions are then held flat for each component of the oil and gas sector through 2050 at 2040 levels (an approximation given that there is no forecast from 2040 to 2050), to assess compliance with an 80 per cent reduction of Canadian emissions from 2005 levels by 2050. Oil sands emissions are held constant at 100 Mt per year through 2050 after reaching the cap in 2025.

The oil sands emissions cap reduces overall emissions of the larger oil and gas sector by 9.3 per cent in 2050. However, even with the cap, emissions from the oil and gas sector alone exceed Canada's commitment to an 80 per cent reduction in overall emissions by 2050, and do so by a large margin of 81 per cent — even if all other sectors of the economy are reduced to zero. Without the oil sands emissions cap, the oil and gas sector would exceed the 2050 target by 101 per cent. And since Canada's target of 80 per cent by 2050 was set, the federal government has

Figure 2: Canadian overall emissions by economic sector through 2018 and forecast for the oil and gas sector through 2050

Oil and gas emissions 2018-2050 are based on CER production forecast assuming an oil sands emissions cap of 100 Mt per year.



Sources: Emissions data to 2018 from Environment and Climate Change Canada (see note 9) and projections from 2018–2040 based on Canada Energy Regulator (see note 8).

Note: Flat emissions from 2040 to 2050 are assumed as the CER forecast ends in 2040.

further committed to net zero by 2050. Clearly, the increases in oil and gas production forecasted by CER are inconsistent with the required emissions reductions.

Given that as of 2018 total Canadian emissions had only been reduced by 0.14 per cent, despite policies put in place to reduce emissions and government assurances that Canada will meet its commitments under the Paris Agreement, it seems highly unlikely that every sector of the economy other than oil and gas production can be reduced to zero by 2050. And even if they could, the oil and gas sector will clearly have to greatly reduce emissions for Canada to have any chance of meeting its emissions-reduction targets. (The IEA's 2019 "sustainable development" scenario requires a 32 per cent reduction in oil production by 2040 to meet global emissions-reduction requirements.)[13] Although there are some opportunities for emissions reduction in the oil and gas sector, such as reducing fugitive methane, reducing steam-to-oil ratios for in situ bitumen production and deploying solvent injection and electrification, these are by no means sufficient without also reducing oil and gas production.

In determining oil supply that is available for export, allowance must be made for imported diluents, as raw bitumen must be blended with diluents at 30 per cent by volume to lower its viscosity and enable movement through a pipeline. Production of condensates and other natural

13 International Energy Agency, *World Energy Outlook 2019* (Paris, France: International Energy Agency, 2019), https://www.iea.org/reports/world-energy-outlook-2019.

gas liquids used as diluents in Western Canada is not sufficient to meet what is required to export the forecasted volume of raw bitumen. There are several forecasts of Western Canadian supply of oil available for domestic refining and export including imported diluents, which are illustrated in Table 2. (In the case of the CER forecast with the emissions cap, the volume of imported diluents required was based on domestic diluent production and the forecasted volume of raw bitumen exports. In the case of the IEA, its forecast for all of Canada was reduced by the CER forecasted production in Eastern Canada in order to obtain Western Canadian supply.)

Table 2: Forecasts of oil supply in Western Canada through 2040 (million barrels per day)

	CER[a] (in 2019) with emissions cap	CER[a] (in 2019) without emissions cap	AER[b] (in 2020)	CAPP[c] (in 2019)	IEA[d] (in 2019)
2018	4.705	4.705	4.527	4.657	5.154
2019	4.864	4.864	4.580	4.802	5.152
2020	5.107	5.107	4.848	5.004	5.218
2021	5.281	5.281	4.998	5.093	5.239
2022	5.394	5.394	5.073	5.226	5.276
2023	5.489	5.489	5.172	5.297	5.305
2024	5.589	5.589	5.292	5.384	5.352
2025	5.646	5.661	5.424	5.472	5.408
2026	5.659	5.817	5.576	5.581	5.454
2027	5.675	5.927	5.687	5.666	5.496
2028	5.696	5.958	5.790	5.753	5.531
2029	5.722	6.042	5.865	5.783	5.555
2030	5.749	6.159		5.867	5.582
2031	5.775	6.285		5.949	5.636
2032	5.799	6.346		6.023	5.695
2033	5.824	6.478		6.139	5.744
2034	5.850	6.538		6.254	5.788
2035	5.874	6.546		6.336	5.828
2036	5.896	6.540			5.834
2037	5.919	6.600			5.846
2038	5.942	6.627			5.861
2039	5.965	6.685			5.877
2040	5.989	6.715			5.893

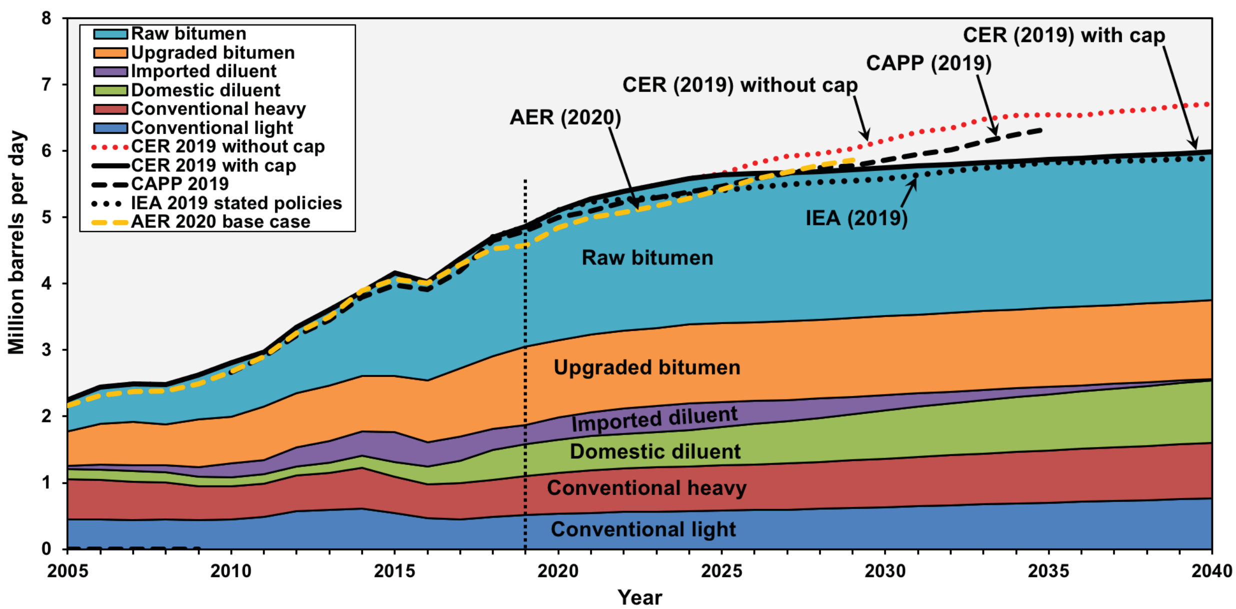
Sources:
a Canada Energy Regulator (see note 8).
b Alberta Energy Regulator. Figures are from their "base case" (see note 11).
c Canadian Association of Petroleum Producers (see note 10).
d International Energy Agency. Figures are IEA's stated policies (see note 12).

Given that as of 2018 total Canadian emissions had only been reduced by 0.14 per cent it seems highly unlikely that every sector of the economy other than oil and gas production can be reduced to zero by 2050.

Figure 3 illustrates the CER forecast (with the emissions cap) broken down by oil type, along with the other forecasts. With the exception of the CER forecast *without* the emissions cap, there is fairly good agreement between the forecasts, even though it is unlikely the other forecasts include the oil sands emissions cap. Also, CAPP's forecast was made in 2019 before the recent downturn in oil markets and the cancellation of projects such as Teck's 260,000-barrel-per-day Frontier mine. CAPP decided, because of the uncertainty in oil markets, it would not provide an updated 2020 forecast, but given the significant weakening of oil markets an updated CAPP forecast would most likely be lower than the 2019 CAPP forecast shown in Table 2 and Figure 3.

Figure 3: Oil supply in Western Canada by oil type through 2040, with a 100 Mt per year oil sands emissions cap

Also shown is the supply forecast by CER without an emissions cap, and forecasts by AER, CAPP and IEA (see Table 2).



Sources: Data from Canada Energy Regulator (see note 8), Alberta Energy Regulator (note 11), Canadian Association of Petroleum Producers (note 10), and International Energy Agency (note 12).

Pipeline requirements given supply forecasts

WESTERN CANADIAN OIL IS USED BOTH DOMESTICALLY IN REFINERIES in the three western provinces and exported to refineries in the US and Eastern Canada. CAPP has enumerated the refinery capacity in Alberta, Saskatchewan and British Columbia,[14] and CER has enumerated the existing and proposed pipeline export capacity.[15]

In addition to pipelines, rail also provides export capacity. In February 2020, 411,991 barrels per day were exported by rail,[16] and the total existing oil-loading capacity of rail in Western Canada is estimated by CAPP at 1,108,000 barrels per day.[17] Although rail is a more expensive option than pipelines, it has the flexibility to access markets not served by pipelines and is three times safer than pipelines in terms of the volume of oil spilled per ton-mile transported.[18]

Although rail is a more expensive option than pipelines, it has the flexibility to access markets not served by pipelines and is three times safer than pipelines in terms of the volume of oil spilled per ton-mile transported.

Table 3 illustrates the total existing and projected export takeaway capacity from Western Canada to the US, Eastern Canada and the West Coast. Pipeline capacities for existing and proposed pipelines are from the CER forecast,[19] and rail capacity is based on 75 per cent of the existing rail oil-loading capacity (assuming that the full rail loading capacity will not be accessible owing to insufficient rail cars and other logistical constraints). Also included is additional capacity announced by Enbridge on its Mainline system beginning in 2020

14 Canadian Association of Petroleum Producers, *2019 Crude Oil Forecast, Markets and Transportation*, https://www.capp.ca/wp-content/uploads/2019/11/CAPP-2019-Crude-Oil-Markets-and-Transportation-338794-1.pdf.

15 Canada Energy Regulator, "Results," *Canada's Energy Future 2019*, updated June 24, 2020, https://www.cer-rec.gc.ca/nrg/ntgrtd/ftr/2019/rslts/index-eng.html, Figure 19.

16 Canada Energy Regulator, "Canadian Crude Oil Exports by Rail — Monthly Data," Crude Oil and Petroleum Products, accessed July 19, 2020, https://www.cer-rec.gc.ca/nrg/sttstc/crdlndptrlmprdct/stt/cndncrdlxprtsrl-eng.html.

17 Canadian Association of Petroleum Producers, *2019 Crude Oil Forecast, Markets and Transportation*, https://www.capp.ca/wp-content/uploads/2019/11/CAPP-2019-Crude-Oil-Markets-and-Transportation-338794-1.pdf.

18 Congressional Research Service, *U.S. Rail Transportation of Crude Oil: Background and Issues for Congress* (Washington, DC: Congressional Research Service, 2014), https://fas.org/sgp/crs/misc/R43390.pdf, 11, Figure 3.

19 Canada Energy Regulator, "Results," *Canada's Energy Future 2019*, updated June 24, 2020, https://www.cer-rec.gc.ca/nrg/ntgrtd/ftr/2019/rslts/index-eng.html, Figure 19.

Table 3: Existing and proposed domestic refinery capacity and pipeline and rail export capacity from Western Canada (million barrels per day)

	AB & SK refineries	Express	Milk River	Aurora Rangeland	Trans Mountain	Enbridge Mainline	Keystone	Mainline enhance-ments	Southern Lights reversal	Line 3 expansion	Rail	Keystone XL	TMX
2014	0.54	0.28	0.10	0.04	0.23	2.34	0.53	0.00	0.00	0.00	0.42	0.00	0.00
2015	0.54	0.28	0.10	0.04	0.25	2.52	0.58	0.00	0.00	0.00	0.42	0.00	0.00
2016	0.57	0.28	0.10	0.04	0.26	2.76	0.57	0.00	0.00	0.00	0.42	0.00	0.00
2017	0.58	0.28	0.10	0.04	0.27	2.81	0.59	0.00	0.00	0.00	0.48	0.00	0.00
2018	0.63	0.28	0.10	0.04	0.26	2.78	0.59	0.00	0.00	0.00	0.64	0.00	0.00
2019	0.65	0.28	0.10	0.05	0.28	2.82	0.58	0.00	0.00	0.00	0.83	0.00	0.00
2020	0.65	0.31	0.10	0.11	0.27	2.87	0.63	0.05	0.00	0.00	0.83	0.00	0.00
2021	0.65	0.32	0.10	0.12	0.28	2.87	0.63	0.05	0.00	0.16	0.83	0.00	0.00
2022	0.65	0.32	0.10	0.12	0.28	2.87	0.63	0.05	0.00	0.36	0.83	0.35	0.00
2023	0.65	0.32	0.10	0.12	0.28	2.87	0.63	0.24	0.14	0.36	0.83	0.81	0.45
2024	0.65	0.32	0.10	0.12	0.28	2.87	0.75	0.24	0.14	0.36	0.83	0.81	0.53
2025	0.72	0.32	0.10	0.12	0.28	2.87	0.75	0.24	0.14	0.36	0.83	0.81	0.53
2026	0.72	0.32	0.10	0.12	0.28	2.87	0.75	0.24	0.14	0.36	0.83	0.81	0.53
2027	0.72	0.32	0.10	0.12	0.28	2.87	0.75	0.24	0.14	0.36	0.83	0.81	0.53
2028	0.72	0.32	0.10	0.12	0.28	2.87	0.75	0.24	0.14	0.36	0.83	0.81	0.53
2029	0.72	0.32	0.10	0.12	0.28	2.87	0.75	0.24	0.14	0.36	0.83	0.81	0.53
2030	0.80	0.32	0.10	0.12	0.28	2.87	0.75	0.24	0.14	0.36	0.83	0.81	0.53
2031	0.80	0.32	0.10	0.12	0.28	2.87	0.75	0.24	0.14	0.36	0.83	0.81	0.53
2032	0.80	0.32	0.10	0.12	0.28	2.87	0.75	0.24	0.14	0.36	0.83	0.81	0.53
2033	0.80	0.32	0.10	0.12	0.28	2.87	0.75	0.24	0.14	0.36	0.83	0.81	0.53
2034	0.80	0.32	0.10	0.12	0.28	2.87	0.75	0.24	0.14	0.36	0.83	0.81	0.53
2035	0.80	0.32	0.10	0.12	0.28	2.87	0.75	0.24	0.14	0.36	0.83	0.81	0.53
2036	0.80	0.32	0.10	0.12	0.28	2.87	0.75	0.24	0.14	0.36	0.83	0.81	0.53
2037	0.80	0.32	0.10	0.12	0.28	2.87	0.75	0.24	0.14	0.36	0.83	0.81	0.53
2038	0.80	0.32	0.10	0.12	0.28	2.87	0.75	0.24	0.14	0.36	0.83	0.81	0.53
2039	0.80	0.32	0.10	0.12	0.28	2.87	0.75	0.24	0.14	0.36	0.83	0.81	0.53
2040	0.80	0.32	0.10	0.12	0.28	2.87	0.75	0.24	0.14	0.36	0.83	0.81	0.53

Note: This table assumes 95 per cent of the capacity given by Enbridge for the enhancement of its Mainline and the Southern Lights reversal; 75 per cent of the oil-loading capacity for rail given by CAPP; and 95 per cent of the capacity given by CAPP for the refineries.

Sources: Data from Canadian Association of Petroleum Producers (see note 10), Canada Energy Regulator (note 15), Enbridge (note 20), Alberta Energy Regulator (note 21), and Canadian Press (note 22).

("Mainline enhancements" in the table), including the reversal of its Southern Lights pipeline for exports, which is currently used to import diluent;[20] enhancements on TC Energy's Keystone pipeline (50,000 barrels per day beginning in 2020,[21] and a further 120,000 barrels

20 Enbridge, "Resilience Discipline Growth" (PowerPoint presentation, investment community presentation, June 2020), https://www.enbridge.com/~/media/Enb/Documents/Investor%20Relations/2020/ENB_Investment_Community_Presentation_June_2020v2.pdf, 45, 50.

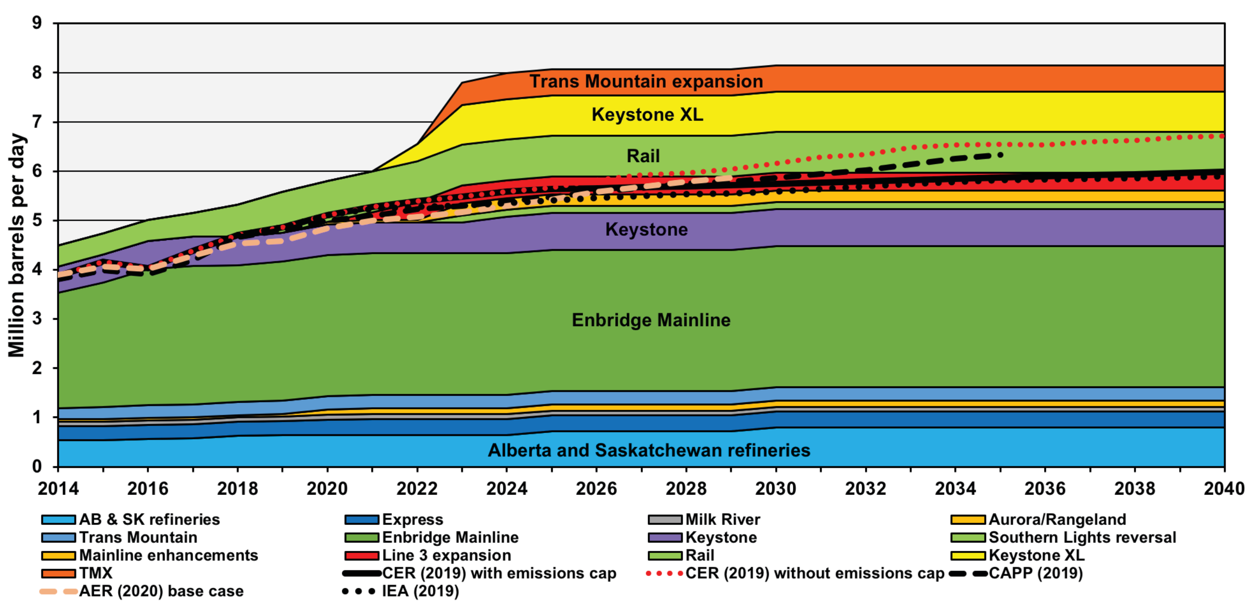
21 Alberta Energy Regulator, "Oil Pipelines," in *ST98: Alberta Energy Outlook* (Calgary, AB: Alberta Energy Regulator, 2020), https://www.aer.ca/providing-information/data-and-reports/statistical-reports/st98/pipelines-and-other-infrastructure/pipelines.html.

per day — an expansion that has been approved by the US).[22] (This additional capacity has been discounted by 5 per cent to reflect the likely maximum usable capacity given maintenance and other possible outages.) The Southern Lights pipeline reversal in 2023 is due to rising domestic diluent production, allowing this pipeline to be repurposed for exports.

The refinery capacity in Table 3 is from CAPP,[23] and includes only Alberta and Saskatchewan, even though BC refineries have a capacity of 67,000 barrels per day. This is because much of the crude oil for BC's Parkland refinery is shipped on the Trans Mountain pipeline and hence this refinery does not reduce the need for export capacity as the Alberta and Saskatchewan refineries do. The refinery capacity in Alberta has also been increased by 79,000 barrels per day in 2025 and again in 2030, to reflect the probable addition of Phases 2 and 3, respectively, of the Sturgeon refinery. (The refinery capacity in Table 3 has been reduced by 5 per cent from the capacity given by CAPP to reflect a maximum usable capacity.)

Figure 4 presents Table 3 as a chart. The various supply forecasts from Table 2 are also shown to compare with existing and proposed Western Canada pipeline and rail export capacity and domestic refinery consumption. Figure 5 expands a section of Figure 4.

Figure 4: Existing and proposed Western Canada export takeaway capacity and domestic refinery consumption from Table 3 compared to Western Canada supply forecasts from Table 2



Sources: For export capacity data, see notes 10, 15 and 20–22 and Table 3. For Western Canada supply data, see notes 8 and 10–12 and Table 2. For refinery capacity, see note 10.

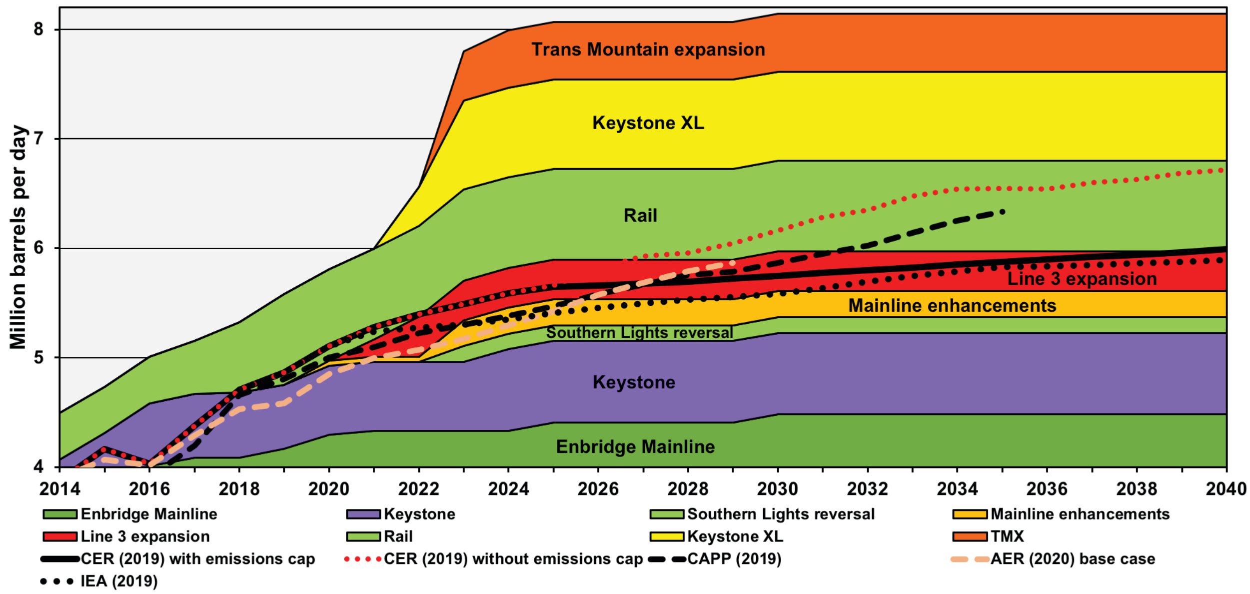
Note: This figure assumes 95 per cent of the capacity given by Enbridge for the enhancement of its Mainline and the Southern Lights reversal; 75 per cent of the oil-loading capacity given by CAPP for rail; and 95 per cent of the capacity given by CAPP for the refineries.

22 Canadian Press, "New U.S. Permit to Boost Keystone Pipeline Oil Exports by Next Year: TC Energy," JWN, July 30, 2020, https://www.jwnenergy.com/article/2020/7/new-us-permit-boost-keystone-pipeline-oil-exports-next-year-tc-energy/.

23 Canadian Association of Petroleum Producers, *2019 Crude Oil Forecast, Markets and Transportation*, https://www.capp.ca/wp-content/uploads/2019/11/CAPP-2019-Crude-Oil-Markets-and-Transportation-338794-1.pdf.

Figure 5: Close-up of Figure 4

Existing and proposed Western Canada export takeaway capacity and domestic refinery consumption from Table 3 compared to Western Canada supply forecasts from Table 2.



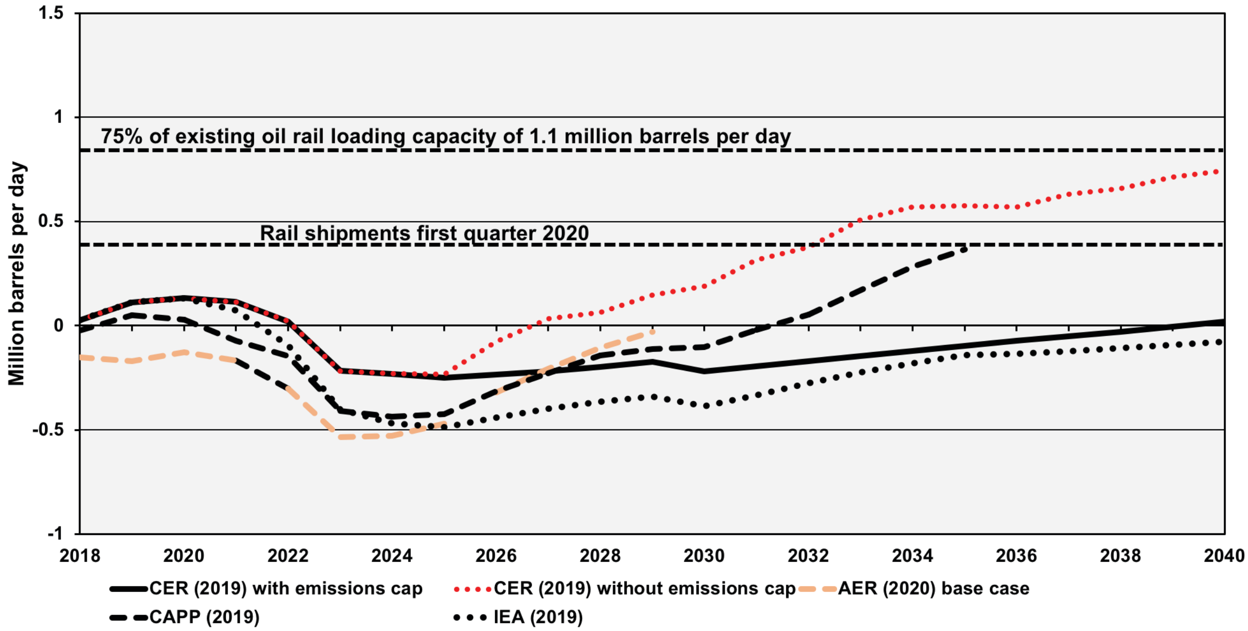
Sources: For export capacity data, see notes 10, 15 and 20–22 and Table 3. For Western Canada supply data, see notes 8 and 10–12 and Table 2. For refinery capacity, see note 10.

Even with a surplus of pipeline export capacity a certain amount of rail would still be used, given rail's flexibility in serving markets not accessible by pipeline. In addition to the rail loading capacity, rail shipments may be constrained by the availability of railcars. As noted above, in February 2020, 411,991 barrels per day were exported by rail, which sets a minimum level for the current availability of railcars.[24]

Figure 6 illustrates the need for rail, based on oil supply forecasts and existing and proposed pipelines and pipeline enhancements (see Tables 2 and 3) —but *without* the construction of the TMX or Keystone XL pipelines. With the exception of the CER forecast without the oil sands emissions cap, only the CAPP forecast requires the full capacity of currently available railcars, and that is not until 2035. (And if the capacity of the cancelled Frontier mine is subtracted from the CAPP forecast, much less rail is required than the currently available railcars within the forecast period.) Given the stated policy of an oil sands emissions cap by the Alberta government, and the extreme overshoot of Canada's emissions-reduction targets even with the cap, the CER forecast without the emissions cap would be extremely unlikely.

24 Canada Energy Regulator, "Canadian Crude Oil Exports by Rail — Monthly Data," accessed July 21, 2020, https://www.cer-rec.gc.ca/en/data-analysis/energy-commodities/crude-oil-petroleum-products/statistics/canadian-crude-oil-exports-rail-monthly-data.html.

Figure 6: Rail requirements if the TMX and Keystone XL pipelines are not constructed



Sources: For export capacity data, see notes 10, 15 and 20–22 and Table 3. For Western Canada supply data, see notes 8 and 10–12 and Table 2. For refinery capacity, see note 10.

Markets and prices for Canadian heavy oil

Oil is a globally priced commodity, and prices are similar in Asia and the US after adjustments for quality and transportation costs are factored in.

A KEY NARRATIVE OF GOVERNMENT AND INDUSTRY IS THAT CANADIAN HEAVY OIL shipped to Asia on TMX will garner higher prices than US exports. This narrative claims that Canadian heavy oil is being unfairly discounted by the US.

In fact, oil is a globally priced commodity, and prices are similar in Asia and the US after adjustments for quality and transportation costs are factored in. The Western Canada Select (WCS) price benchmark for Canadian heavy oil is set at Hardisty, Alberta; and the West Texas Intermediate (WTI) benchmark to which WCS is frequently compared is set at Cushing, Oklahoma. WTI is of a higher quality than WCS, with a quality differential typically from US$6 to US$8 per barrel, and in addition it costs from US$6 to US$7 per barrel to transport oil by pipeline from Hardisty to Cushing. As a result, the WCS benchmark typically averages from US$12 to US$15 per barrel lower than WTI. This differential — or discount — averaged US$13.74 per barrel over 2019 and the first half of 2020,[25] and CER forecasts a differential of US$12.50 per barrel from 2022 through 2040.[26]

This discount can vary, however, if there are shipping constraints — as was the case in late 2018 when the differential briefly exceeded US$40 per barrel.[27] The discount may also vary due to supply constraints, as was seen recently due to the economic fallout from the global pandemic. The pandemic-induced collapse in demand pushed the differential below US$5 per barrel owing to reduced shipments to complex refineries in the US Midwest and on the Gulf Coast, which are equipped for heavy-oil refining.[28] Heavy, sour crude oil, such as WCS, requires specialized add-ons to refineries to optimally refine the oil. These include cokers and other equipment, which significantly increase the refinery construction cost.

25 Government of Alberta, "Oil Prices," Economic Dashboard, *Government of Alberta* (website), accessed July 31, 2020, https://economicdashboard.alberta.ca/OilPrice.

26 Canada Energy Regulator, "Assumptions," *Canada's Energy Future 2019*, updated June 24, 2020, https://www.cer-rec.gc.ca/nrg/ntgrtd/ftr/2019/ssmptns/index-eng.html, Figure 1.

27 Government of Alberta, "Oil Prices," Economic Dashboard, *Government of Alberta* (website), accessed July 31, 2020, https://economicdashboard.alberta.ca/OilPrice.

28 Reuters, "Heavy Discount Narrows on Final Day of August Trading," *BOE Report*, July 16, 2020, https://boereport.com/2020/07/16/heavy-discount-narrows-on-final-day-of-august-trading/.

Only about 12 per cent of global refinery throughput was heavy, sour crude oil in 2018.[29] More than half of this heavy-oil demand was in North America, concentrated in the US Midwest and on the Gulf Coast. Table 4 breaks down the demand for heavy oil by region. The US Gulf Coast, which has 29 per cent of the world's heavy oil refining capacity, has historically relied on Mexico and Venezuela for the bulk of its supplies; however, Canada has become increasingly important in recent years as supply from these sources decline. Mexico's production of heavy oil has been in terminal decline since peaking in 2004, and Venezuela's production has long been in decline owing to both lack of investment and political disruptions. The recent embargo by the US of Venezuela has completely cut off further imports. Figure 7 illustrates US imports of heavy, sour crude oil by country and importing region.

Canada provides virtually all heavy-oil supply to the US Midwest because the close proximity is a transportation cost advantage, and is increasing its supply to the US Gulf Coast.

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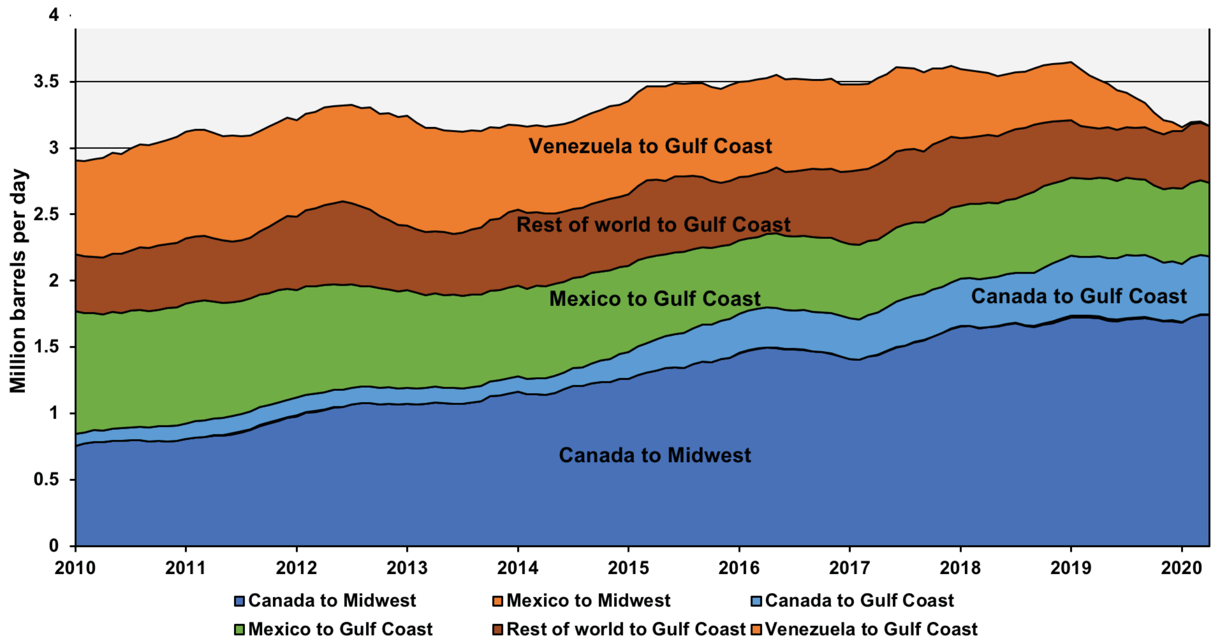
Table 4: Global demand for heavy oil by region in 2018

Region	% of global demand	Million barrels per day
US Gulf Coast	29%	2.79
Elsewhere in North America	26%	2.51
Asia	23%	2.22
Europe	7%	0.67
Commonwealth independent states	3%	0.29
Middle East	7%	0.67
Latin America	5%	0.48
Total	**100%**	**9.64**

Source: Data from IHS Markit (see note 29).

29 IHS Markit, *Looking North: A US Perspective on Canadian Heavy Oil* (London, UK: IHS Markit, 2018), https://ihsmarkit.com/products/energy-industry-oil-sands-dialogue.html.

Figure 7: US imports of heavy, sour crude oil by country to the Midwest and Gulf Coast, 2010–2020



Source: Data from Energy Information Agency's U.S. Crude Import Tracking Tool (accessed July 2, 2020), https://www.eia.gov/petroleum/imports/browser/#/?vs=PET_IMPORTS.WORLD-US-ALL.A.

Reduced netbacks for exports to Asia

A PRINCIPAL NARRATIVE OF GOVERNMENT AND INDUSTRY in justifying the construction of TMX is that the increased tidewater access will yield higher netbacks (profit after accounting for production and shipping costs) for Canadian producers compared with US exports. We can evaluate this narrative by comparing the price of heavy, sour crude oil sold to the US and the Far East, and the transportation costs involved to each destination.

Mexican Maya is a heavy, sour crude oil, comparable to WCS in quality (in terms of API (American Petroleum Institute) gravity and sulphur content), that is traded globally. Roughly 60 per cent of Maya exports from Mexico in recent years went to the US (mainly to the Gulf Coast), 25 per cent to Europe and 15 per cent to the Far East.[30] WCS sold on the US Gulf Coast or in the Far East would fetch prices comparable to Maya.

Table 5 illustrates the price paid for Maya cargoes bound for the US (mainly the Gulf Coast, although some Maya is imported by California) and the Far East. The price paid for US-bound cargoes has averaged US$1.90 per barrel above the price paid for Far East–bound cargoes over the 2010–2020 period, and has averaged US$4.27 per barrel above the Far East over the 2014–2020 period.[31]

The price data for Mexican Maya in recent years tells us that Canadian heavy oil exported to Asia is likely to command a lower price than if sold to the US. This is to be expected given that oil is a globally traded and priced commodity, and once quality differences and transportation costs are accounted for, oil should trade at roughly similar prices everywhere. In the case of heavy oil, however, the fact that complex refineries designed to process heavy oil are concentrated in the US means that the US on average pays a premium compared with the Far East, which has less processing capacity. (Heavy oil has higher yields of diesel and certain other products compared with the medium and light oil processed in conventional refineries.)

The fact that complex refineries designed to process heavy oil are concentrated in the US means that the US on average pays a premium compared with the Far East, which has less processing capacity.

30 Pemex, *Statistical Yearbook 2018* (Mexico City, Mexico: Pemex, 2019), https://www.pemex.com/en/investors/publications/Anuario%20Estadstico%20Archivos/statisticalyearbook2018.pdf. See years 2010 to 2018. “Petroleum Statistics May 2020,” Investors, Pemex, accessed May 2020, https://www.pemex.com/en/investors/publications/Paginas/petroleum-statistics.aspx. See years 2019 and 2020; 2020 is based on the average of January through May.

31 Ibid.

Table 5: Price of Mexican Maya heavy, sour crude oil, 2010-2020

Table 5 compares the price of Maya crude in cargoes purchased in Mexico bound for the US and for the Far East and shows the price difference, in US dollars per barrel.

	US	Far East	US minus Far East
2010	$70.22	$74.27	-$4.05
2011	$98.36	$101.41	-$3.05
2012	$99.66	$101.48	-$1.82
2013	$96.82	$96.88	-$0.06
2014	$85.77	$78.02	$7.75
2015	$43.45	$36.07	$7.38
2016	$36.20	$34.63	$1.57
2017	$46.88	$46.54	$0.34
2018	$62.62	$60.07	$2.55
2019	$57.09	$54.21	$2.88
2020*	$32.84	$25.45	$7.39
Average discount in Far East 2014–2020			**$4.27**
Average discount in Far East 2010–2020			**$1.90**

Sources: Data from Pemex, *Statistical Yearbook 2018*; and "Petroleum Statistics May 2020" (see note 30).
*Average of January through May 2020.

Another important consideration in determining netbacks for Canadian producers is transportation cost. Would transportation from Edmonton to the Westridge terminal on TMX and tanker transport to Asia cost less than transport from Hardisty, Alberta, to the US Midwest and Gulf Coast? Table 6 summarizes the pipeline and tanker tolls to each destination. Tolls are from the 2013 Kinder Morgan application for TMX.[32] As noted in this application, tolls are adjusted by CAD$0.07 per barrel for each $100 million increase in the cost of the pipeline expansion. As discussed above, the cost of the expansion has increased from CAD$5.4 billion when proposed in 2013 to the most recent estimate of CAD$12.6 billion. All prices in Table 6 have been adjusted for inflation and converted to 2019 dollars. The cost of tanker transport from the Westridge terminal to south China is from the 2015 Muse Stancil report filed by Kinder Morgan.

32 Trans Mountain Pipeline ULC, "Final Form of the FSA," Appendix 7 (A3E7D3) in Application for Approval of the Transportation Service and Toll Methodology for the Expanded Trans Mountain Pipeline System (RH-001-2012), January 10, 2013, https://apps.neb-one.gc.ca/REGDOCS/File/Download/902023, 10; and Trans Mountain Pipeline ULC, "Final form of the FSA — TSA Schedules," Appendix 9 (A3E7D5) in Application for Approval of the Transportation Service and Toll Methodology for the Expanded Trans Mountain Pipeline System (RH-001-2012), revised January 10, 2013, https://apps.neb-one.gc.ca/REGDOCS/File/Download/901941.

Table 6: Tolls for transporting Canadian heavy oil to south China compared to the US Midwest or Gulf Coast, with toll-price penalties for selling to Asia

	Toll (in USD, 2019) with initial cost estimate of CAD$ 6 billion for TMX	Toll (in USD, 2019) with final cost estimate of CAD$ 12.6 billion for TMX
Edmonton to Westridge terminal		
20-year heavy-oil open-season toll limit[a] >75 kbd[b]	$4.42	$8.11
20-year heavy-oil indicative fixed + variable toll[c] >75 kbd	$3.58	$7.27
Tanker voyage from Westridge terminal to South China		
Muse Stancil (2015) Cold Lake blend heavy oil in 2019	$4.21	
Total tolls from Edmonton to South China		
20-year heavy-oil open-season toll limit >75 kbd	$8.63	$12.32
20-year heavy-oil indicative fixed + variable toll >75 kbd	$7.79	$11.48
Hardisty, AB, to the US Midwest		
Enbridge Mainline heavy oil >80 kbd (as of May 2020, Hardisty to Ohio or Michigan)	$5.58	
CAPP 2019 heavy oil (Hardisty to Chicago)	$4.40	
Hardisty, AB, to the US Gulf Coast		
CAPP 2019 (via Enbridge/Seaway pipeline) 15-year, 50+ kbd committed volumes	$9.60	
CAPP 2019 (via Keystone/TC Energy)	$8.80	
Toll-price penalty for selling to Asia, with final cost estimate for TMX		
Midwest (Ohio or Michigan) versus south China (open-season toll limit)	$6.74	
Midwest (Ohio or Michigan) versus south China (indicative fixed + variable toll)	$5.90	
Midwest (Chicago) versus south China (open-season toll limit)	$7.92	
Midwest (Chicago) versus south China (indicative fixed + variable toll)	$7.08	
US Gulf Coast via Enbridge Seaway pipeline versus south China (open-season toll limit)	$2.72	
US Gulf Coast via Enbridge Seaway pipeline versus south China (indicative fixed + variable toll)	$1.88	
US Gulf Coast via Keystone/TC Energy versus south China (open-season toll limit)	$3.52	
US Gulf Coast via Keystone/TC Energy versus south China (indicative fixed + variable toll)	$2.68	

Sources: Data about tolls from Hardisty to Ohio or Michigan are from Enbridge, *International Joint Rate Tariff*, CER No. 475/FERC No. 37.13.0 (Calgary, AB: Enbridge, 2020), https://www.enbridge.com/~/media/Enb/Documents/Tariffs/2020/CDMN%20CER%20475%20FERC%2037130%20TLD%20LKH.pdf; tolls from Hardisty to Chicago or Gulf Coast are from CAPP (see note 10); tolls from Edmonton to Westridge Terminal are from Trans Mountain Pipeline ULC (see note 32); and tanker tolls are from Muse Stancil, *Market Prospects and Benefits Analysis of the Trans Mountain Expansion Project for Trans Mountain Pipeline (ULC)* (Addison, TX: Muse Stancil, 2015), https://apps.neb-one.gc.ca/REGDOCS/File/Download/2825856, 62, Table A-3.

a Open-season toll limit as defined by Kinder-Morgan (see footnote 32).

b kbd = thousand barrels per day.

c Indicative fixed + variable toll as defined by Kinder-Morgan (see footnote 32).

Canadian producers are likely to lose money if their oil is transported via TMX to Asia.

Depending on the toll type and pipeline route, transportation costs to south China are from US$1.88 to US$3.52 per barrel more expensive than to the US Gulf Coast, and from US$ 5.90 to US$7.92 per barrel more expensive than to the US Midwest. Adding the difference in transportation cost to the discount in price selling to Asia compared to the US, and the netback loss per barrel to Canadian producers by selling heavy oil to Asia is US$4 to US$6 per barrel or more.

Thus, the government and industry narrative that Canadian producers will have higher netbacks because of TMX is not supported by the evidence. Canadian producers are in fact likely to lose money if their oil is transported via TMX to Asia. Very little heavy oil on the existing Trans Mountain pipeline is transported to Asia. Instead, seaborne shipments go primarily to the West Coast of the US, which confirms the fact that there is no bonanza for shippers in Asia.

Conclusion

THERE HAVE BEEN SIGNIFICANT NEW DEVELOPMENTS THAT BEAR ON THE NEED for TMX since the government purchased the project in 2018 and approved it for the second time in 2019. These include:

- Announced expansions and optimizations of existing pipelines that will increase export capacity over the next two to three years, including the Enbridge mainline, and the Aurora-Rangeland, Keystone and Express pipelines.
- The reversal of the Southern Lights pipeline for export use in 2023.
- The likely completion of the Line 3 expansion project in 2021.
- The release of new production forecasts since June 2019, by the Canada Energy Regulator (CER, formerly the National Energy Board), Alberta Energy Regulator (AER), Canadian Association of Petroleum Producers (CAPP) and International Energy Agency (IEA).
- The release of the latest update of Alberta's Oil Sands Emissions Limit Act in January 2020.
- The release of Canada's 2020 emissions report by economic sector which allows an updated assessment of future emissions from the oil and gas sector and compliance with Alberta's 2020 Oil Sands Emissions Limit Act.
- The increase in the cost of the TMX project from $7.4 billion when it was purchased in 2018 to $12.6 billion in February 2020, which will significantly increase shipping costs for Canadian producers selling oil to Asia compared to US exports.
- The COVID-19 pandemic of 2020 which has resulted in an unprecedented decline in the demand for oil and is likely to reduce demand in the longer term.

Emissions from the oil and gas sector alone are on track to exceed Canada's emissions reduction target in 2050 by 81 per cent.

Key conclusions of this report are as follows:

1. Emissions from the oil and gas sector alone are on track to exceed Canada's emissions reduction target in 2050 by 81 per cent—even with a 100 megatonne (Mt) per year cap on oil sands emissions (as evidenced from the latest CER oil and gas production forecast, coupled with the latest Environment Canada emissions report). Without the cap, emissions from the oil and gas sector would exceed this target by 101 per cent.
2. The increase in oil production forecast by CER (with an oil sands emissions cap), AER, CAPP and IEA can easily be accommodated for the next decade with existing pipelines, including announced optimizations and the Line 3 expansion, without rail or the TMX and Keystone XL pipelines. These forecasts, however, substantially overstate likely pro-

duction increases as they do not account for the impact of demand reduction resulting from the COVID-19 pandemic or the need to reduce emissions from oil and gas production to meet Canada's emissions reduction targets.

The $12.6 billion the government plans to spend on the construction of TMX is counterproductive, as it is unlikely to increase the profits of Canadian producers or result in a revenue stream that will both cover construction costs and provide additional funds to reduce emissions in a meaningful timeframe.

3. There is no price premium to be had selling Canadian heavy oil to Asia. In fact, based on Pemex sales of Maya heavy oil (comparable to Canada's Western Canada Select heavy oil benchmark) over the past six years, cargos bound for the Far East sold at an average discount of $4.27 per barrel compared to cargos bound for the US. (The higher price paid for heavy oil in the US reflects the fact that the US has more than half of the world's refineries equipped to process heavy oil.)
4. Transportation costs to Asia from Alberta are also higher than to the US Midwest or Gulf Coast. Transport costs to south China are between US$1.88 to US$3.52 per barrel higher than to the US Gulf Coast, and from US$5.90 to US$7.92 per barrel higher than to the US Midwest.
5. Thus, the narrative that the Trans Mountain Expansion project will lead to increased netbacks for Canadian producers is not supported by the evidence. The discount from selling Canadian heavy oil to Asia, coupled with higher transportation costs, will lead to a reduction in netbacks for Canadian producers, compared to the US, of US$4 to US$6 per barrel or more.
6. Therefore, the government's claim that TMX must be built in order to provide increased revenue to Canadian oil producers and $500 million per year to reduce emissions must be viewed with extreme skepticism. An expenditure of $12.6 billion tax dollars on a project that will likely reduce revenues for Canadian producers would certainly be better spent directly on reducing emissions.

Canada's emissions reduction policies have so far proven to be ineffective at the scale required. Although Canada has committed to a 30 per cent reduction of emissions by 2030 (from 2005 levels), emissions were down only 0.14 per cent by 2018. Emissions in Alberta, where the oil to fill TMX would be produced, have increased by 17.5 per cent since 2005.

The $12.6 billion the government plans to spend on the construction of TMX is counterproductive, as it is unlikely to increase the profits of Canadian producers or result in a revenue stream that will both cover construction costs and provide additional funds to reduce emissions in a meaningful timeframe. If anything, TMX will exacerbate the emissions problem by incentivizing additional production growth while diverting funds that could otherwise be spent on actual emissions reduction. TMX will also increase the risk of oil spills along its route and in the marine environment. Canada urgently requires a viable strategy that will effectively address future energy security needs, environmental objectives, and emissions reduction targets.

CORPORATE
MAPPING PROJECT

This report is part of the Corporate Mapping Project (CMP), a research and public engagement initiative investigating the power of the fossil fuel industry. The CMP is jointly led by the University of Victoria, Canadian Centre for Policy Alternatives BC and Saskatchewan Offices, and Parkland Institute. The initiative is a partnership of academic and community-based researchers and advisors who share a commitment to advancing reliable knowledge that supports citizen action and transparent public policy making. This research was supported by the Social Sciences and Humanities Research Council of Canada (SSHRC).

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