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Enbridge Pipelines Inc. - Line 3 Replacement Program

Review of Related Upstream Greenhouse Gas Emissions Estimates

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Executive Summary

This document provides an estimate of the upstream greenhouse gas (GHG) emissions associated with the Line 3 Replacement Program, and a discussion of the conditions under which they could be considered incremental.

The Line 3 Replacement Program proposes to replace sections of the existing Line 3 pipeline between Hardisty, Alberta, and Gretna, Manitoba, and involves the installation of new, and the replacement of existing, infrastructure (e.g., storage tanks, valves and pumps) as well as the decommissioning of the existing Line 3 pipeline. The design average annual capacity of the existing Line 3 pipeline is 760,000 barrels per day. However, in recent years, the pipeline has only been operating at an annual capacity of 390,000 barrels per day. The Line 3 Replacement Program would enable the company to return operation to the original design capacity of the existing Line 3 pipeline.

Environment and Climate Change Canada estimated the upstream GHG emissions in Canada associated with the production and processing of crude oil that could be transported by the Line 3 replacement pipeline if the project is approved. The projections for GHG emissions and production used for this review include the estimated future impacts of existing policies and measures as of September 2015. A number of important measures and targets to reduce GHG emissions from the oil and gas sector have been announced since that time, including the Government of Canada's commitment to reduce methane emissions from the oil and gas sector by 40% to 45% below 2012 levels by 2025. While this analysis focuses on policies implemented as of September 2015 and does not reflect the impact of additional federal, provincial or territorial measures announced or under development, it is recognized that future improved practices will mitigate emissions.

The upstream GHG emissions associated with the Line 3 replacement pipeline, transporting 760,000 barrels per day, could be between 21 and 27 megatonnes of carbon dioxide equivalent per year. Considering only the 370,000 barrels per day capacity added by the Line 3 Replacement Program, the upstream GHG emissions could range from 10 to 13 megatonnes of carbon dioxide equivalent per year. The degree to which the estimated emissions would be incremental depends on the considerations that drive investment decisions for crude oil producers, namely the expected price of oil, the availability and costs of other transportation modes (e.g., crude-by-rail), whether other pipeline projects are built, and costs of production.

If the Line 3 replacement pipeline is the only additional pipeline capacity added from Western Canada and the netback price for the marginal barrel of oil sands production does not change with its construction, the project would not be expected to cause incremental production or upstream emissions. However, there are circumstances under which building only the Line 3 replacement pipeline could result in improved financial returns (i.e., improved netback price) for proposed oil sands projects and, therefore, cause some incremental production and upstream emissions.

If additional pipeline capacity, including the Line 3 replacement pipeline, is built such that shipping crude-by-rail was no longer needed, it is likely that the netback price on the marginal barrel of oil sands

production would increase. A portion of the emissions calculated in this review would therefore be incremental.

Incremental production is likely to be greater when long-term Canadian light oil prices are in a range between \$60-80 per barrel (2015 U.S. dollars). At prices higher than this range, many oil sands projects would be profitable even if transporting crude oil by rail was the only option. Therefore, incremental production is less likely to be enabled. If long-term oil prices were expected to be lower than this range, significant new investment in oil sands production may not be expected regardless of the mode of transportation (i.e., rail or pipeline). In addition, there are challenges associated with attributing any incremental GHG emissions to a specific pipeline given that a number of pipeline projects with similar construction timelines and capacities have been proposed in Canada.

Incremental oil sands production could have an impact on global supply and prices. Some portion of this would displace crude oil supplied at the margin. In this case, the impact on global emissions would be the difference in well-to-tank GHG emissions. Incremental production could also increase total global oil supply, lowering global prices and increasing the quantity of oil consumed. The emissions impact of this portion would be the full well-to-wheels lifecycle emissions. Given that a substantial amount of crude oil is expected to be financially viable in a similar crude oil price range to Canadian oil sands, it is expected that a large portion of incremental production would be expected to displace other types of crude oil, rather than increasing total oil supply.

Introduction

As part of its January 27, 2016 announcement of interim principles, the Government of Canada has committed to assess the upstream greenhouse gas (GHG) emissions associated with projects undergoing an environmental assessment (1). Environmental assessments of projects already include an assessment of the direct emissions caused by a project.

The following review of upstream GHG emissions for the Enbridge Pipelines Inc. (Enbridge) Line 3 Replacement Program (Project) includes a project description, a quantitative estimation of the GHG emissions released as a result of upstream production associated with the Project (Part A), and a discussion of the Project's potential impact on Canadian and global GHG emissions (Part B).

Project Description

Enbridge's existing Line 3 pipeline is a 863.6 millimeter (mm) -diameter, 1,600-kilometer (km) pipeline between Edmonton, Alberta and Superior, Wisconsin. The existing Line 3 pipeline is part of the larger Enbridge *Mainline System* that includes Lines 1, 2, 3, 4, and 67 (2). The *Mainline System* allows crude oil, natural gas liquids and refined petroleum product to be transported from the hub in Edmonton, Alberta, to locations in Canada and further south into the U.S (3). Since it began operating in the late 1960s, the annual average capacity of the existing Line 3 pipeline has varied between an original design average annual capacity in the range of 760,000 barrels per day (bbl/d) and its current low of 390,000 bbl/d which has resulted from operating conditions including voluntary pressure restrictions put in place by Enbridge to ensure the continued safe operation of the pipeline (4).

On November 5, 2014, Enbridge submitted an application for the Line 3 Replacement Program to the National Energy Board (NEB). The Line 3 Replacement Program proposes to replace sections of the existing 1,067-km pipeline between Hardisty, Alberta, and Gretna, Manitoba, and includes (5):

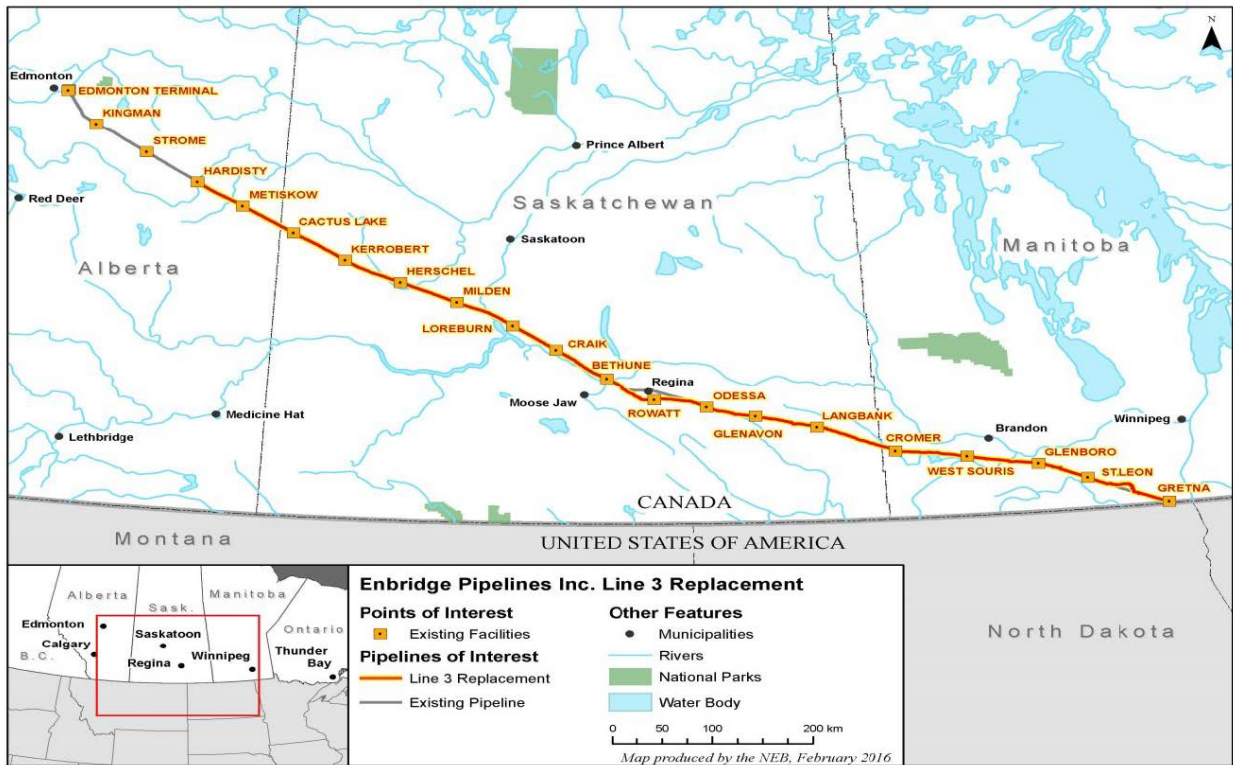
- the replacement of the existing Line 3 pipeline (863.6 mm) with a new pipeline (914.4 mm);
- the addition of remotely operated sectionalizing valves;
- the replacement of pumps and associated infrastructure and equipment;
- the addition of tankage at the Hardisty Terminal; and
- the decommissioning of the existing Line 3 pipeline.

The proposed Line 3 replacement pipeline is shown in Figure 1.

Based on Enbridge's application to the NEB, if constructed, the Line 3 replacement pipeline can be expected to operate at the original design average annual capacity of the existing Line 3 pipeline (760,000 bbl/d). This represents an additional capacity of 370,000 bbl/d when compared to the current operating capacity of the existing Line 3 pipeline. The application also indicates that in the absence of the Project, it is expected that Enbridge will continue to operate the existing Line 3 pipeline at its current capacity of 390,000 bbl/d. The Project description indicates that the Line 3 replacement pipeline could

transport light, medium and heavy crudes (6). Finally, at this time, oil from the Alberta Clipper pipeline (Line 67) is being shipped over the U.S. border on the existing Line 3 pipeline, bringing the operating capacity of the trans-border section of the Line 3 pipeline closer to its permitted capacity of 760,000 bbl/d. If the Line 3 replacement pipeline is constructed, it is expected that the oil from the Alberta Clipper would no longer be transported on Line 3.

Figure 1 – Project Map



If approved, the projected in-service date for the Line 3 replacement pipeline is expected to be early 2019. The Project will enhance the *Mainline System's* capacity to deliver crude oil to markets in Ontario, Quebec, and the Midwestern U.S. (7). Enbridge is also pursuing the expansion of pipelines entirely in the U.S.: Lines 2 (Flanagan South, Seaway), and 61 (Southern Access Project). Midwestern pipeline connections in the U.S. would enable greater access to southern U.S. crude oil markets, including the U.S. Gulf Coast, which offers an expanded market for Canada's growing crude oil production (8).

Part A. Estimation of the Upstream GHG Emissions

Part A of this review provides quantitative estimates of the GHG emissions released as a result of upstream extraction and processing of crude oil associated with the Project. This includes emissions from combustion, industrial processes, flaring, venting, and fugitive sources. The GHG emissions from these sources contain carbon dioxide, methane and nitrous oxide. These constituents of GHG emissions were added together taking into account their respective global warming potentials. The scope of this

review does not extend to *indirect* upstream emissions, such as those related to land-use changes and those generated during the production of purchased inputs including equipment, grid electricity and fuels. Those emissions have only been considered if they are not distinguishable from the *direct* upstream emissions. Emissions related to the transportation of crude oil from facilities to the Line 3 replacement pipeline were also not considered, but are expected to be minor when compared to other upstream emission sources associated with the Project.

The methods for extracting and processing different types of crude oil vary; as a result, different type of crude oil may have different levels of GHG emissions. In addition, the types of crude oil and refined product (i.e., the crude oil mixⁱ) that could enter the pipeline will change during its operational life to reflect operational requirements and market demand. Due to the potential variability associated with the crude oil mix, including the quantities and types of crude oil transported by the Line 3 replacement pipeline, emissions estimates are presented for several potential scenarios.

A.1 Project Capacity

Upstream emissions were estimated for the design average annual capacity of the Line 3 replacement pipeline (760,000 bbl/dⁱⁱ) as well as a for the additional pipeline capacity (370,000 bbl/d) that the Project could add. Whether or not the estimated upstream GHG emissions associated with the latter could result in incremental GHG emissions in Canada is not discussed in Part A of this review. A discussion of the implications on Canada's GHG emissions of the additional pipeline capacity that would be enabled by the Project is included in Part Bⁱⁱⁱ.

A.2 Crude Oil Mix

For the purposes of this review, the many different types of crude oil that could be transported by the Line 3 replacement pipeline were aggregated into the six categories outlined below. The product categories have been selected to allow for the use of emissions data from Environment and Climate Change Canada (ECCC) (9) and production trends from the NEB (10) to develop emissions factors (see A.5 below).

Conventional Light This includes low density crude oil streams that flow through wells and pipelines without processing or dilution.

Conventional Heavy This includes high density crude oil streams that flow through wells and pipelines without processing or dilution.

CSS Heavy This includes high density crude oil streams produced using Cyclic Steam Stimulation (CSS). In this *in situ* method, steam is injected into a heavy crude oil reservoir. This introduces heat that thins the oil and allows it to be extracted. This type of crude oil requires that diluent be added in order to flow

ⁱ The proportion of different categories of crude oil (such as diluted bitumen or conventional light crude oil) transported in the pipeline over time is the crude oil mix.

ⁱⁱ Pipelines do not necessarily operate at full capacity on a continuous basis and therefore the estimates presented in this assessment represent the maximum upstream emissions that could be associated with the Project for a given product mix.

ⁱⁱⁱ In the context of this review, the word additional is used when discussing the added capacity that the Project would bring. The word incremental is used when discussing the production (and resulting emissions) that could be directly enabled by this Project.

through pipelines; for the purpose of this review it was assumed that 30% of the volume of this type of crude oil is diluent. Extraction involving the addition of solvent with steam is also included.

SAGD Heavy This includes high density crude oil streams produced using Steam-Assisted Gravity Drainage (SAGD). In this *in situ* method, a pair of horizontal wells is used. High pressure steam is injected into the upper well to heat the oil and reduce its viscosity, causing the heated oil to drain into the lower well, where it is pumped out. It was assumed that 30% of the volume of this type of crude oil is diluent. Extraction involving the addition of solvent with steam is also included.

Mined Bitumen This includes high density crude oil streams that originate from surface mining of bitumen-containing deposit and processing to extract bitumen. It was assumed that 20% of the volume of this type of crude oil is diluent. This category does not include mined bitumen upgraded to synthetic crude oil, which falls into the *Synthetic* category below.

Synthetic This includes low density crude oil streams produced by upgrading high density crude oil.

A.3 Crude Oil Mix Scenarios

Based on the NEB’s *Estimated Canadian Crude Oil Exports by Type and Destination*, it was estimated that the existing Line 3 pipeline presently transports a crude oil mix of 30% conventional light and 70% synthetic crude oil (11). In the future, the production of heavy oil using CSS, SAGD, and mining extraction methods is projected to account for a higher proportion of the overall Canadian production. The Line 3 replacement pipeline will be capable of transporting a range of crude oil types from the Western Canadian Sedimentary Basin (WCSB). Three potential crude oil mixes were considered for this review and form the basis of the scenarios modeled to estimate upstream GHG emissions. Table 1 provides the proportions of each crude oil category described above for the three crude oil mixes.

Table 1 – Crude Oil Mixes

Crude Oil Category	Present Mix (%)	Historic Mix (%)	Future Mix*
<i>Conventional Light</i>	30	20	15
<i>Conventional Heavy</i>	0	6	18
<i>CSS Heavy</i>	0	2	8
<i>SAGD Heavy</i>	0	15	22
<i>Mined Bitumen</i>	0	5	8
<i>Synthetic</i>	70	53	29

* The future crude oil mix reflecting the WCSB production varies year over year based on the NEB Reference Case (10). The Future Mix for 2019 is presented here as an example. The data for all the years of the modelling period (2019-2030) is included in Annex A.

Using combinations of the three crude oil mixes presented above, ECCC estimated emissions for four different scenarios to assess a range of upstream emissions that could be associated with the Project. In

the following scenarios, the pipeline capacity used for estimating the upstream emissions (see A.1 above) do not vary during the modelling period (2019-2030).

A.3.1 Scenario 1

In this scenario, the crude oil mix was assumed to be the *Present Mix*: 30% conventional light crude oil and 70% synthetic crude oil. The crude oil mix does not vary throughout the modelling period (2019-2030).

A.3.2 Scenario 2

In this scenario, the crude oil mix was assumed to be the *Future Mix*. The respective proportions of the different crude oil categories vary throughout the modelling period, and are presented in Annex A.

A.3.3 Scenario 3

In this scenario, the current annual capacity of the existing Line 3 pipeline (390,000 bbl/d) is expected to transport the *Present Mix*: 30% conventional light crude oil and 70% synthetic crude oil. The additional capacity of 370,000 bbl/d resulting from the Project is expected to transport the *Historic Mix*: 53% synthetic crude oil, 20% conventional light crude oil, 15% heavy crude oil extracted with SAGD, 6% conventional heavy crude oil, 5% mined bitumen, and 2% heavy crude oil extracted with CSS. The crude oil mix does not vary throughout the modelling period (2019-2030).

A.3.4 Scenario 4

In this scenario, the crude oil mix was assumed to be the *Historic Mix*: 53% synthetic crude oil, 20% conventional light crude oil, 15% heavy crude oil extracted with SAGD, 6% conventional heavy crude oil, 5% mined bitumen, and 2% heavy crude oil extracted with CSS. The crude oil mix does not vary throughout the modelling period (2019-2030).

A.4 Estimated Upstream GHG Emissions

The resulting range of estimated upstream GHG emissions associated with the Project is presented below in Table 2 for the four scenarios described above. For each scenario, estimates are provided for both the full capacity of the replacement pipeline (760,000 bbl/d) and for the capacity that the Project could add (370,000 bbl/d). The methodology used to estimate the emission is described in A.5 below.

Table 2 – Estimated Upstream GHG Emissions (Mt of CO₂ eq per year)

Year	Pipeline Capacity (Mbbbl/d)	Scenario			
		1	2	3	4
2019	760	26.1	21.5	25.0	23.8
	370	12.7	10.5	12.2	11.6
2020	760	26.2	21.5	25.1	23.9
	370	12.8	10.5	12.2	11.6
2021	760	26.3	21.5	25.2	24.0
	370	12.8	10.5	12.3	11.7

Year	Pipeline Capacity (Mbbbl/d)	Scenario			
		1	2	3	4
2022	760	26.4	21.5	25.2	24.0
	370	12.8	10.4	12.3	11.7
2023	760	26.4	21.3	25.2	24.0
	370	12.9	10.4	12.3	11.7
2024	760	26.4	21.2	25.2	24.0
	370	12.9	10.3	12.3	11.7
2025	760	26.7	21.1	25.5	24.2
	370	13.0	10.3	12.4	11.8
2026	760	26.7	21.0	25.5	24.2
	370	13.0	10.2	12.4	11.8
2027	760	26.7	20.9	25.5	24.2
	370	13.0	10.2	12.4	11.8
2028	760	26.7	20.8	25.4	24.1
	370	13.0	10.1	12.4	11.7
2029	760	26.7	20.7	25.4	24.1
	370	13.0	10.1	12.4	11.7
2030	760	26.7	20.7	25.4	24.1
	370	13.0	10.1	12.4	11.7

ECCC projects that the upstream GHG emissions in Canada resulting from the production and processing of crude oil associated with the Line 3 Replacement Program could range from 21 to 27 Mt of CO₂ eq per year. Considering only the 370,000 bbl/d capacity added by the Line 3 Replacement Program, emissions could range from 10 to 13 Mt of CO₂ eq per year.

As illustrated in Table 2, the estimated upstream GHG emissions are significantly influenced by the crude oil mix that will be transported by the Line 3 replacement pipeline. There is uncertainty in the actual crude oil mix that will be transported and therefore, the actual associated upstream GHG emissions. As well, this part of the review (Part A) does not consider whether these emissions would occur in the absence of the Project. Given these inherent uncertainties, the values presented are estimates of a range of possible upstream GHG emissions associated with the Project.

A.5 GHG Forecast Approach

The estimates in Table 2 were developed using GHG emission projections from ECCC's *Canada's Second Biennial Report on Climate Change* submitted to the United Nations Framework Convention on Climate Change (UNFCCC) (9) and the NEB's production projections from the report *Canada's Energy Future 2016 – Energy Supply and Demand Projections to 2040 (EF 2016)* (10). ECCC used the details of the projected GHG emissions and productions that were specific to the *with current measures* reference scenario (9). This reference scenario includes actions taken by governments, consumers and businesses

up to 2013, as well as the future impacts of existing policies and measures that have been put in place as of September 2015.

A number of recently announced provincial government policies, such as those outlined in Alberta's *Climate Leadership Plan* (12) and British Columbia's *Climate Leadership Plan* (13), will have an impact on Canadian GHG emissions, but were not reflected in *Canada's Second Biennial Report on Climate Change* as the details of these policies were not available at the time of publication. Alberta's *Climate Leadership Plan* includes a commitment to cap emissions from oil sands facilities at 100 Mt in any year, reduce methane emissions from oil and gas operations by 45% by 2025, set performance standards for large industrial emitters, and apply a carbon levy to fuels.

On March 3, 2016, First Ministers adopted the *Vancouver Declaration on Clean Growth and Climate Change*, in which they commit to develop a concrete plan to achieve Canada's international climate commitments and become a leader in the global clean growth economy (14). The Government of Canada has also committed to reduce methane emissions from the oil and gas sector by 40% to 45% below 2012 levels by 2025. While this analysis focuses on policies implemented as of September 2015 and does not reflect the impact of additional federal, provincial, or territorial measures announced or under development, it is recognized that future improved practices will mitigate emissions. As measures to meet targets are implemented, they will be incorporated into future emissions projections and future upstream GHG reviews.

The details of ECCC's GHG projections provide emissions and production forecasts according to specific crude oil categories. The emissions include emissions resulting from combustion, industrial processes, flaring, venting, and fugitive sources that are associated with the extraction and processing activities of these crude oil categories. The GHG emissions from these sources include carbon dioxide, methane, and nitrous oxide, and these constituents of GHG emissions are added together taking into account their respective global warming potential.

For the purposes of this review, ECCC developed emission factors representing the relative upstream emissions contributions per unit volume of crude oil category. Each category of crude oil that may enter the pipeline has a specific emission factor that depends on the emissions generated during its extraction and upgrading, if applicable.

In order to develop emission factors ECCC divided projected emissions for extraction and upgrading, as appropriate, by the respective production projection. The resulting emission factors are presented in Table 3. The methodology used to develop the emission factors is presented in Annex B of this review.

The unit volume for each crude oil category was determined by taking into account the Project's expected capacity and expected crude oil mix. Each crude oil category's unit volume was adjusted (where applicable) to exclude the diluent portion associated with transporting that category of crude oil. The total diluent volume transported by the pipeline also has upstream emissions associated with its production. Most of the diluent is expected to be imported according to the NEB (10). Upstream emissions were only estimated for the portion of the diluent that is expected to be produced in Canada.

The emission factors for conventional light crude oil were used for the diluent portion that is produced in Canada.

Table 3 – GHG Emission Factors (kg of CO₂ eq/barrel)

Year	Conv. Light	Conv. Heavy	CSS Heavy	SAGD Heavy	Mined Bitumen	Synthetic
2019	68.5	85.9	82.3	75.1	44.1	105.1
2020	68.7	85.8	82.4	75.4	44.2	105.4
2021	69.0	85.8	82.4	75.8	44.4	105.9
2022	69.2	85.7	82.4	76.1	44.6	106.2
2023	69.3	85.7	82.4	76.1	44.7	106.3
2024	69.4	85.7	82.4	76.1	44.7	106.3
2025	69.5	85.7	82.4	76.1	44.7	108.0
2026	69.6	85.7	82.4	75.9	44.7	107.9
2027	69.7	85.7	82.5	75.8	44.7	107.7
2028	69.7	85.7	82.6	75.5	44.7	107.5
2029	69.8	85.8	82.7	75.4	44.7	107.4
2030	69.8	85.8	82.8	75.3	44.7	107.4

A.6 Facility-Reported Data

Emission factors for some crude oil categories can also be determined using facility-reported emissions and production data. For comparison purposes, ECCC also estimated upstream GHG emission using emission factors calculated from facility-reported data. Facility emissions were obtained from the federal *Greenhouse Gas Reporting Program* and the *Specified Gas Emitters Regulation* provincial regime in Alberta. Facility production was obtained from provincial reporting sources. The resulting range of estimated upstream GHG emissions associated with the Project is presented below in Table 4 for the four scenarios described in A.3 above. The results are substantially the same as those estimated in Table 2.

The emission factors calculated using facility-reported data are presented in Table 5. The methodology used to develop these emission factors is presented in Annex B of this review.

Table 4 – Estimated Upstream GHG Emissions – Facility-Reported Data (Mt of CO₂ eq per year)

Year	Pipeline Capacity (Mbbbl/d)	Scenario			
		1	2	3	4
2019	760	26.1	21.5	25.0	23.8
	370	12.7	10.5	12.2	11.6
2020	760	26.2	21.5	25.1	23.9
	370	12.8	10.5	12.2	11.6
2021	760	26.3	21.5	25.2	24.0
	370	12.8	10.5	12.3	11.7
2022	760	26.4	21.5	25.2	24.0
	370	12.8	10.4	12.3	11.7
2023	760	26.4	21.3	25.2	24.0
	370	12.9	10.4	12.3	11.7
2024	760	26.4	21.2	25.2	24.0
	370	12.9	10.3	12.3	11.7
2025	760	26.7	21.1	25.5	24.2
	370	13.0	10.3	12.4	11.8
2026	760	26.7	21.0	25.5	24.2
	370	13.0	10.2	12.4	11.8
2027	760	26.7	20.9	25.5	24.2
	370	13.0	10.2	12.4	11.8
2028	760	26.7	20.8	25.4	24.1
	370	13.0	10.1	12.4	11.7
2029	760	26.7	20.7	25.4	24.1
	370	13.0	10.1	12.4	11.7
2030	760	26.7	20.7	25.4	24.1
	370	13.0	10.1	12.4	11.7

Table 5 – GHG Emission Factors – Facility-Reported Data (kg of CO₂ eq/barrel)*

Year	CSS Heavy	SAGD Heavy	Mined Bitumen	Synthetic
2019	84.1	71.0	40.6	107.6
2020	84.1	71.3	40.7	108.0
2021	84.2	71.7	40.9	108.4
2022	84.2	72.0	41.0	108.8
2023	84.1	72.0	41.1	108.8
2024	84.1	72.0	41.1	108.8
2025	84.1	72.0	41.2	110.6
2026	84.2	71.8	41.2	110.6

Year	CSS Heavy	SAGD Heavy	Mined Bitumen	Synthetic
2027	84.2	71.7	41.1	110.4
2028	84.3	71.5	41.1	110.1
2029	84.4	71.3	41.1	110.0
2030	84.6	71.2	41.1	110.0

* It was not possible to use facility-reported data to calculate emission factors for the conventional light and conventional heavy crude oil categories. For these crude oil categories, emission factors from Table 3 were used.

Part B. Impacts on Canadian and Global Upstream GHG Emissions

B.1 Introduction

Part A presents estimates for a range of upstream GHG emissions that could be associated with the production and processing of crude oil products transported by the Line 3 replacement pipeline. However, given that there are multiple transportation modes available for crude oil, it is possible that a portion of the upstream emissions calculated in Part A would occur with or without the Project, or, for that matter with or without additional pipeline capacity more generally.

If the same quantity of oil production were expected to occur in the absence of the Project as in a scenario where the Project were built, the Project would not enable incremental oil production and would therefore have no impact on upstream GHG emissions in Canada. If, however, the oil production would not occur in the absence of the Project, but would only occur if the Project was built, then there would be incremental upstream emissions in Canada. Given that incremental oil production will lead to incremental GHG emissions, these terms are used interchangeably in this review.

Part B discusses the conditions under which the production of the oil volumes associated with a fully-utilized Line 3 replacement pipeline would be incremental. Part B focuses on the additional volumes (+370,000 bbl/d) of crude oil that could be transported by a fully-utilized Line 3 replacement pipeline rather than the emissions associated with all of the oil (760,000 bbl/d) transported by the pipeline. This Part assumes that if the Project did not proceed, Enbridge would continue to operate the existing Line 3 pipeline at its current rate in the future (390,000 bbl/d), which is consistent with Enbridge's regulatory filings with the NEB. It is also important to consider that oil volumes from the Alberta Clipper pipeline (Enbridge's Line 67) are transiting the Canada/U.S. border on the existing Line 3 pipeline at this time over a section of the pipeline that is not under voluntary pressure restriction. On this section, the existing Line 3 pipeline could be running closer to its originally permitted capacity. The 370,000 bbl/d of additional capacity could be considered a high-end estimate of additional pipeline capacity, depending on the status of the U.S. portion of the Alberta Clipper expansion and the amount of oil that flows on that pipeline if the Line 3 Replacement Program is undertaken.

Part B is divided into four sections. The *Canadian Oil Production Outlook* section discusses the NEB's and ECCC's projections for future oil production and upstream GHG emissions growth, respectively, and Canada's climate commitments in relation to oil sands production growth. The *Crude Oil Pipeline and Crude-by-Rail Infrastructure* section discusses crude-by-rail movements and capacity in North America, and compares the economics of crude-by-rail versus pipelines. The *Incremental Emissions and Pipeline Capacity Additions* section outlines scenarios in which pipeline capacity additions could enable incremental production, and important considerations related to global oil consumption and GHG emissions. The *Conclusions* section outlines the key findings of Part B. Several limitations associated with the overall assessment in Part B are provided in Annex C.

B.2 Canadian Oil Production Outlook

This section discusses the NEB's projections of Canadian oil production growth, GHG emissions projections made by ECCC, the global outlook for oil, and the potential markets for Canadian crude oil. It

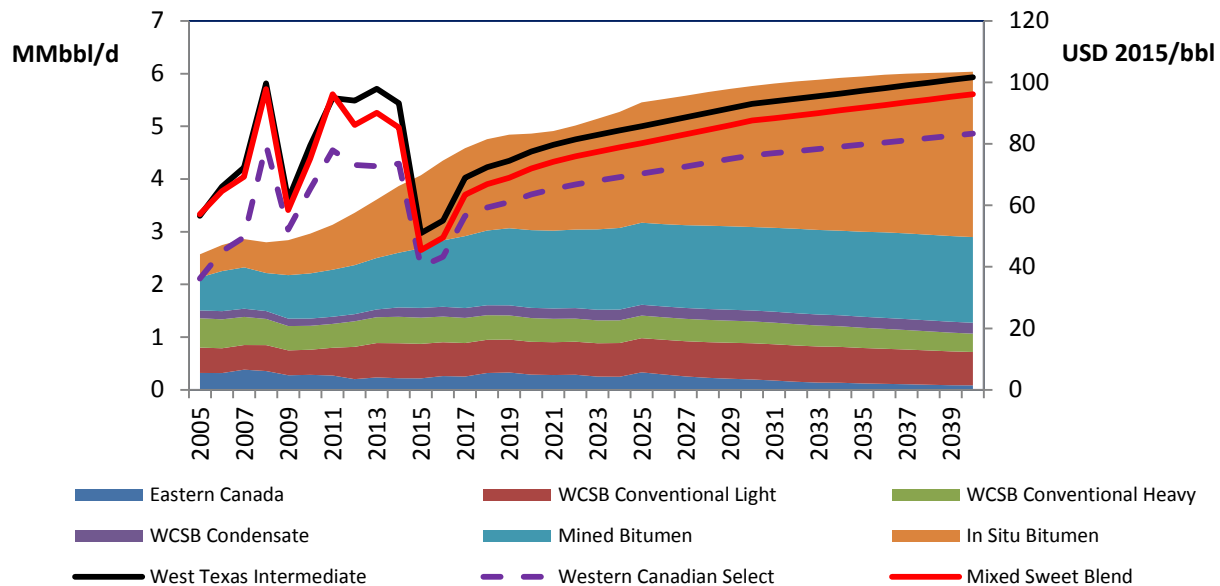
then discusses oil market uncertainties and concludes with a discussion of the NEB’s *Constrained Pipeline* case from the report *Canada’s Energy Future 2016 – Energy Supply and Demand Projections to 2040 (EF 2016)* (10) and the potential implications of Canada’s GHG reduction commitments for oil sands growth.

B.2.1 Canadian Oil Supply Growth

In 2015, Canada produced an estimated 3.9 million barrels per day (MMbbl/d) of crude oil, of which 2.4 MMbbl/d, or approximately 61%, was from the oil sands. According to the *Reference Case* in the NEB’s *EF 2016* report, oil production in Canada is expected to increase by nearly 58% and reach 6.1 MMbbl/d of production by 2040. The NEB estimates that 79% (or 4.8 MMbbl/d) of this amount will come from the oil sands, and that this will be largely composed of bitumen production from *in situ* operations. The remainder of oil sands growth under the *Reference Case* is expected from mining operations, with only limited growth in upgraded bitumen over the forecast period. Projected growth in oil sands production under the *Reference Case* represents a doubling by 2040 from 2014 levels (See Figure 2) (15). Most production forecasts, including the NEB’s *Reference*, *High Price*, and *Low Price Cases*, assume pipeline capacity will be built as required.

Since most Canadian oil production growth is expected to be comprised of *in situ* bitumen, Canadian crude oil production growth transported on any additional pipeline or rail transportation capacity in the future will be largely comprised of diluted bitumen (dilbit) blends from Western Canada^{iv}. This conclusion informs the discussion throughout Part B.

Figure 2 – Total Canadian Crude Oil and Equivalent Production and Oil Price Forecast (*Reference Case*)



Source: NEB (10)

^{iv} In Part A, diluted bitumen is included in the SAGD Heavy, Mined Bitumen, and CSS Heavy categories

In the *EF 2016 Reference Case*, the price of West Texas Intermediate (WTI) – a North American crude oil benchmark – averages USD 51/bbl (\$2015) in 2015, increasing to USD 78/bbl in 2020, and finally reaching USD 102/bbl by 2040. Western Canadian Select (WCS), the benchmark heavy crude oil from Western Canada, is priced USD 17/bbl lower than WTI over the projection period, while Canadian Mixed Sweet Blend (MSW), the benchmark light crude oil from Western Canada, is priced USD 5.50/bbl lower than WTI.

EF 2016 also examines a *Low Price Case* and a *High Price Case* and presents the impacts on Canadian crude oil production. In the *Low Price Case*, the WTI crude oil price is on average USD 26/bbl (\$2015) lower than the *Reference Case*, reaching USD 80/bbl by 2040. In the *High Price Case*, the WTI crude oil price is on average USD 26/bbl higher than the *Reference Case*, reaching USD 134/bbl by 2040. In the *Low Price Case*, oil sands production grows marginally after projects currently under construction are completed, and reaches 3.8 MMbbl/d in 2040, approximately 21% lower than the *Reference Case*. In the *High Price Case*, oil sands production reaches 5.3 MMbbl/d in 2040, approximately 6% higher than the *Reference Case* (10).

Despite the current low oil price environment, the NEB expects that most production growth in the oil sands up to 2020 will remain unaffected. However, projects with completion dates in the longer term, or projects that have not started construction, are likely to see delays and deferrals if oil prices stay low (10). Forecasts from the Canadian Association of Petroleum Producers (CAPP) and the Alberta Energy Regulator (AER) also show that most oil sands supply growth to the end of the decade can be considered ‘locked in’, and is unlikely to be reduced by a significant amount. ECCC estimates around 576,000 bbl/d of oil sands capacity is expected to finish construction and come online between 2016 and 2019 (see Annex D). After including the necessary diluent for transporting diluted bitumen, additional pipeline-grade product available for transport by 2020 increases to nearly 720,000 bbl/d^v.

B.2.2 Canada’s GHG Emissions Projections

ECCC projects that Canada’s total annual GHG emissions will increase to 815 Mt in 2030 from 726 Mt in 2013, under its reference or *with current measures* scenario as reported in *Canada’s Second Biennial Report on Climate Change* (9). This scenario is based on historical data and actions taken by governments, consumers and businesses up to 2013, as well as the estimated future impacts of existing policies and measures that have been put in place as of September 2015 (without taking into account the contribution of the land use, land-use change and forestry sector).

The growth in emissions to 2030 is driven largely by growth in the upstream oil and gas sector and, in particular, from the oil sands. ECCC projections indicate that GHG emissions from the oil sands are expected to increase from 62 Mt in 2013, to 90 Mt in 2020 and up to 116 Mt in 2030. Emissions from oil sands *in situ* projects are expected to increase by 40 Mt between 2013 and 2030 while GHG emissions

^v Much of the estimated 576,000 bbl/d of capacity under construction is bitumen production which would need to be diluted with a light hydrocarbon to be transported on a pipeline. Assuming a 30% diluent blend (70% bitumen) for *in situ* projects and a 20% diluent blend for bitumen mines, the figure increases to 720,000 bbl/d of pipeline grade oil sands production.

from bitumen mining and upgrading operations are projected to increase by 10 Mt and 5 Mt, respectively, between 2013 and 2030 (9).

B.2.3 Global Crude Oil Outlook

Oil demand growth is expected to be driven in the future by emerging economies, particularly China, the Middle East, and India (16). In its *New Policies Scenario*, the International Energy Agency (IEA) projects world crude oil and liquids demand to grow from 90.6 MMbbl/d in 2014 to 95.9 MMbbl/d in 2020, and up to 103.5 MMbbl/d by 2040. Of the 0.9 MMbbl/d of demand growth expected annually through to 2020, the IEA estimates that 0.35 MMbbl/d will be from China, 0.2 MMbbl/d from the Middle East, and 0.18 MMbbl/d from India, with the remainder from other regions. By 2040, the IEA's *New Policies Scenario* estimates that Chinese crude oil and liquids demand will reach 15.3 MMbbl/d, up from 10.5 MMbbl/d in 2014. The IEA expects oil demand growth to slow after 2020 (16).

Countries from the Organization for Economic Cooperation and Development (OECD) are expected to continue to experience structural declines in crude oil and liquids demand, with the IEA estimating an average annual decline of 1.2%. Respectively, Japanese, European, and U.S. demand for oil and liquids is forecast to decline approximately 44%, 35%, and 27% from 2014 levels by 2040. In the IEA's *450 Scenario*, in which the world has a 50% chance of limiting the long-term increase in average global temperatures to no more than 2°C, global oil and liquids demand peaks by 2020 at 93.7 MMbbl/d and declines 18% from 2014 levels to 74.1 MMbbl/d in 2040. However, the IEA notes that in both the *New Policies* and the *450 Scenario* a substantial amount of new oil resources are required to be produced since a large amount of investment is expected to compensate for declining output at existing oil and gas fields (16).

B.2.4 North American Markets for Canadian Oil Sands Production Growth

In 2015, 99% of Canadian crude oil exports went to the U.S. The U.S. is divided into five petroleum markets termed Petroleum Administration Defense Districts (PADD): PADD 1 (East Coast); PADD 2 (Midwest); PADD 3 (Gulf Coast); PADD 4 (Rocky Mountain), and; PADD 5 (West Coast). The Project would increase pipeline capacity to PADD 2 (Midwest). This report assumes that PADD 3 is the ultimate destination for increased volumes of crude oil transported on pipelines to PADD 2 due to^{vi}:

- 1) The fact that PADD 2 is already a major consumer of Canadian crude and has limited capacity to further increase refining of heavy oil volumes without future refinery upgrades;
- 2) The connections to other pipelines within PADD 2 that move oil to Cushing, Oklahoma and, ultimately, PADD 3, and;
- 3) The expected growth in heavy oil production in Canada and the substantial amount of existing heavy oil refining capacity in PADD 3.

PADD 2 is the second largest refining market in the U.S. and the largest market for Canadian crude oil. In 2015, refineries in PADD 2 processed 3.6 MMbbl/d of oil which represented 22% of U.S. crude oil

^{vi} This report acknowledges that expanding the pipeline system can change the composition of crude oil on specific pipelines and that the Line 3 replacement pipeline could be used to transport crude oil that is currently being produced. As such, its construction could shift barrels onto it, enabling more heavy oil to flow on other pipelines.

consumption (see Table 6) (17) (11). In addition, PADD 2 refineries use large volumes of heavy oil as inputs. In 2015, refineries in PADD 2 processed 1.5 MMbbl/d of heavy oil, or about 33%, of all U.S. heavy oil refinery inputs, and of this 1.46 MMbbl/d was heavy oil from Canada. Exports to PADD 2 accounted for 67% of all Canadian heavy oil exports in that year^{vii}.

Table 6 – U.S. Refining Capacity, Oil Receipts, and Canadian Exports by PADD in 2015

	Total Refinery Crude Oil Receipts		Total Refinery Heavy Oil Receipts		Canadian Exports of Bitumen and Heavy Oil	
	MMbbl/d	% of Total	MMbbl/d	% of Total	MMbbl/d	% of Total
PADD 1 (East Coast)	1.1	7%	0.2	4%	0.1	5%
PADD 2 (Midwest)	3.6	22%	1.5	33%	1.46	67%
PADD 3 (Gulf Coast)	8.5	52%	2.2	49%	0.38	17%
PADD 4 (Rocky Mountains)	0.6	4%	0.2	4%	0.19	9%
PADD 5 (West Coast)	2.4	15%	0.4	9%	0.06	3%
U.S. Total	16.2		4.4		2.2	

Source: CAPP forecast (8), U.S. Energy Information Administration Data (17) and National Energy Board of Canada (10).

Both the NEB and CAPP have noted that refineries in PADD 2 have little scope to process more heavy oil. Expansion of heavy oil processing capacity at PADD 2 refineries is likely to be inhibited by the growth in light tight oil production from the U.S., which has reduced the expected profitability of further refinery conversion projects (8) (10). As such, growth in Canadian oil sands production is more likely to be transported to markets other than PADD 2.

PADD 3 includes refineries in the U.S. Gulf Coast and is one of the largest refining markets in the world. In 2015, refineries in PADD 3 processed 8.5 MMbbl/d of crude oil (8) (17). PADD 3 is the largest U.S. market for heavy crude oil, processing approximately 2.2 MMbbl/d, or 50% of heavy crude in the U.S. in 2015. Despite being a major market for crude oil, in 2015, PADD 3 refineries sourced only about 4.5%, or 0.4 MMbbl/d of their crude oil inputs from Canada. PADD 3 is a competitive market as refineries have access to various types of crude oil due to tidewater access and their proximity to major pipeline hubs. Mexico and Venezuela are key suppliers of crude oil to PADD 3, supplying approximately 1.4 MMbbl/d, or 16% of total crude consumed in 2015 by PADD 3 refineries (8) (10).

PADD 5, Ontario and Quebec were also considered for this analysis, but these markets were either not connected to the pipeline being discussed (e.g. PADD 5), or had less scale or less ability to process heavy oil under current refinery configurations. In the future, companies could invest in these regions to process more Canadian heavy crude; however, the timeline for such investments is uncertain.

^{vii} Heavy oil is defined to include both heavy conventional crudes and oil sands bitumen, but there are varying definitions. For instance, the NEB defines heavy oil as any crude with an API gravity less than 25 degrees, while CAPP defines heavy as any crude with an API gravity below 28 degrees.

B.2.5 Oil Market Uncertainties

B.2.5.1 Oil Prices

WTI crude oil prices have declined significantly since the summer of 2014, from a high of USD 107/bbl in June 2014 to as low as USD 26/bbl in February 2016, and averaged USD 40.28/bbl in the first half of 2016. Primary factors contributing to the recent decline in world oil prices are the increase in North American unconventional crude oil production, slower economic growth in emerging markets, and the decision by the Organization of the Petroleum Exporting Countries (OPEC) to increase output levels in the face of these developments. At current prices (August 2016), many Canadian oil and gas companies are posting losses and companies are reducing spending on longer-term projects, rather than those that are in the later stages of construction (18). For example, the NEB reported that over 700,000 bbl/d of oil sands capacity not yet under construction has been cancelled or delayed in recent years, most with start-up dates in the post-2020 timeframe (19).

B.2.5.2 Pipeline Constraints

Increasing production from U.S. light tight oil and from Canada's oil sands in recent years caused pipeline bottlenecks in North America. This had consequences for crude oil prices, in particular, price differentials between inland North American crude oil benchmarks and international benchmarks.

In a market without infrastructure constraints, the differences between benchmark prices should largely reflect differences in crude oil quality and transportation costs. However, between 2011 and 2014, WCS crude traded at an average discount to Maya (a similar quality crude oil) of USD 21.50/bbl, more than triple the 2007-2010 average of USD 6.40/bbl (10). Pipeline constraints and resulting price differentials caused many companies to invest in crude-by-rail capacity between 2012 and 2014 (discussed below).

At this time, many pipelines from the WCSB are at, or nearing, their effective capacities as evidenced by recent pipeline apportionment^{viii}. The NEB's *Canada's Pipeline Transportation System 2016* report (20) notes that oil export capacity was tight in 2015, citing increases in crude oil production from the oil sands and lack of additional pipeline capacity as the major contributing factors. According to the NEB, many of the major exporting oil and liquids pipelines (including Enbridge Mainline, Trans Mountain, and Keystone) had average utilization rates above 85% in 2015. IHS Inc. estimates that exports from the WCSB could reach effective pipeline capacity by late-2016 or early-2017, resulting in greater movements of crude-by-rail (21). Current pipeline projects, including the Line 3 Replacement Program, which have been proposed to and/or approved by the NEB have a cumulative capacity of over 3.4 MMbbl/d (8).

^{viii} In its fourth quarter 2015 Management's Discussion and Analysis (45), Enbridge Energy noted that the *Mainline System* pipeline network was expected to remain under apportionment in early 2016. However, recent financial reports indicate that, at this time, the *Mainline System* is not under apportionment as a result of recent expansion projects by Enbridge Energy. The Trans Mountain pipeline has been under apportionment for a number of years. Apportionment occurs when the total desired amount of crude oil transportation space exceeds the available shipping capacity for that type of crude oil on a pipeline. The space on a pipeline under apportionment is rationed between bidding parties, typically on a pro-rata basis. The gap in pipeline takeaway capacity from the WCSB is expected to increase to the end of the decade with the expected growth in oil sands production.

B.2.5.3 NEB Constrained Oil Pipeline Capacity Case (Constrained Case)

As part of the *EF 2016* report, the NEB examined a scenario which illustrates the potential impacts of a constrained oil transportation system. The NEB *Constrained Case* assumes that no major proposed export pipelines (e.g. Keystone XL, Northern Gateway, Trans Mountain Expansion, and Energy East) are built; however, the Line 3 Replacement Program is completed. As such, the *Constrained Case* assumes that the Enbridge Mainline expansions (including the Line 3 Replacement Program) and crude-by-rail are the only options available to transport Canadian crude oil production growth. Further, the NEB analysis, like this review, assumes that the primary growth market for Canadian exports of heavy crude from the oil sands, in the absence of additional pipeline capacity, would be the U.S. Gulf Coast (see section B.2.4 above).

Constrained pipeline capacity leads to transportation costs that are higher than what they otherwise would be in the *Reference Case*. For example, the price differential between WCS and WTI grows by USD 10/bbl relative to the *Reference Case*, representing the incremental cost to transport crude on rail to the U.S. Gulf Coast. These lower prices lead to lower cash flow, lower investment, and ultimately to lower oil production in 2040 in the *Constrained Case* relative to the NEB's *Reference Case*.

In this *Constrained Case*, Canadian oil production continues to grow, albeit with a time lag of around five years (2020-2025) where oil production growth effectively ceases. Delayed projects and reduced investment results in Canadian oil production being approximately 0.5 MMbbl/d (or 8%) lower than the *Reference Case*, dropping from 6.1 MMbbl/d to 5.6 MMbbl/d in 2040. As would be expected, oil sands production is affected the most since this is where most production growth occurs in the *Reference Case*.

B.2.6 Canadian Climate Change Commitments and Oil Sands Production

In December 2015, Canada and 194 other countries reached the Paris Agreement at the UNFCCC's 21st Conference of the Parties (UNFCCC's COP21). Under this agreement, countries committed to the long-term goal to limit average temperature rise to well below 2°C and pursue efforts to limit the increase to 1.5°C. Under the UNFCCC, Canada committed to a target of reducing emissions 30% below 2005 levels by 2030.

A number of studies have considered scenarios where global warming is limited to 2°C. However, these scenarios utilize different modelling frameworks and can have vastly different assumptions around technological and economic progress. The role of technological innovation, policy design and stringency, and consumer and business behaviour, both in Canada and globally, can have significant implications for Canadian oil sands production in these scenarios. As a result of the differing treatment of these variables, conclusions across scenarios are not uniform, and the impact on Canadian oil sands production is not clear. However, a common result of modelling efforts to analyze a 2°C world is that overall global crude oil consumption declines relative to the status quo.

Some studies have presented scenarios where oil sands production growth is not fully consistent with a world in which global warming is limited to 2°C. For example, a 2014 study found that Canadian bitumen production could increase to 4.1 MMbbl/d by 2035 and be consistent with a 2°C target, but only with a

rapid deployment and scale-up of carbon capture and storage (CCS) technology from 2020 and the decarbonization of energy inputs (22). In a 2015 study with a longer timeframe for analysis, the same authors found that, even with widespread CCS deployment from 2025, Canadian oil sands production would be significantly curtailed. The authors concluded that 74% of Canadian crude oil reserves would have to remain unexploited to be consistent with a 2°C target and estimated that, without CCS, all bitumen production in Canada would have to cease by 2040 to be consistent with a 2°C target (23).

Other projections show that oil sands production could continue to expand from current levels while still limiting warming to 2°C: for example, the IEA World Energy Outlook's *450 Scenario* (16). The IEA's 2014 World Energy Investment Outlook concludes that most non-OPEC crude oil reserves (including Canada's oil sands) could be produced in a 2°C world (24).

A report by Carbon Management Canada concluded that Canada's 2030 reductions target is one of several possible emissions reduction pathways consistent with a 2°C objective. The report assumes significant innovation in currently unknown technology, and highlights the importance of low carbon extraction techniques for the oil sands and carbon capture and storage for Canada's decarbonisation aspirations (25).

As noted above, the variations in these findings are driven by different modelling frameworks and assumptions around the future energy mix and rates of technological progress. It is not yet clear what policy frameworks will be put into place provincially, nationally, and globally and it is extremely challenging to predict which technologies may be commercialized in the future. Given the difficulties in predicting these variables, the analysis in this review uses a forecast based on the NEB's *EF 2016* report that incorporates current policies and commercialized technologies. Over time, new technologies and policies will be developed that will change the emissions intensity and economic feasibility of oil production both in Canada and globally, as well as act to change the attractiveness of alternatives to oil.

B.3 Crude Oil Pipeline and Crude-by-Rail Infrastructure

For crude oil production to grow in the absence of pipeline development there must be a viable transportation alternative. Companies are expected to pursue new oil production opportunities if they can earn their required rate of return on investment, regardless of the mode of transport. In the case of crude-by-rail, the conditions for new oil production are:

- i. Sufficient crude-by-rail capacity exists or can expand to meet demand, and;
- ii. Project economics under future oil price expectations remain sufficiently attractive when shipping crude-by-rail.

It is worth noting that when transporting oil on similar distances, rail has been generally recognized as being more emissions intensive than transporting oil by pipeline. The emission intensity of a Class 1 freight railway is approximately 15.8 kg CO₂ eq/1000 tonne kilometres (26). In comparison, ECCC estimates that the emission intensity of an oil pipeline traversing Alberta, Saskatchewan, and Manitoba is 12.9 kg CO₂ eq/1000 tonne kilometres, including emissions associated with grid electricity used to power pumping stations along the pipeline. As such, in the absence of the Project, if crude is transported via rail instead, this transportation option would result in higher direct transportation

emissions in Canada. It is important to note that several factors influence the emission intensity of specific rail and crude oil pipelines routes. Therefore, depending on the specific project in question, the difference in emission intensity between the two modes of crude oil transport will vary. Due to differences in methodology, ECCC’s estimated emission intensity for pipeline operations may not be comparable to the estimates of operational emissions that the applicant has made as a part of their submission to the NEB.

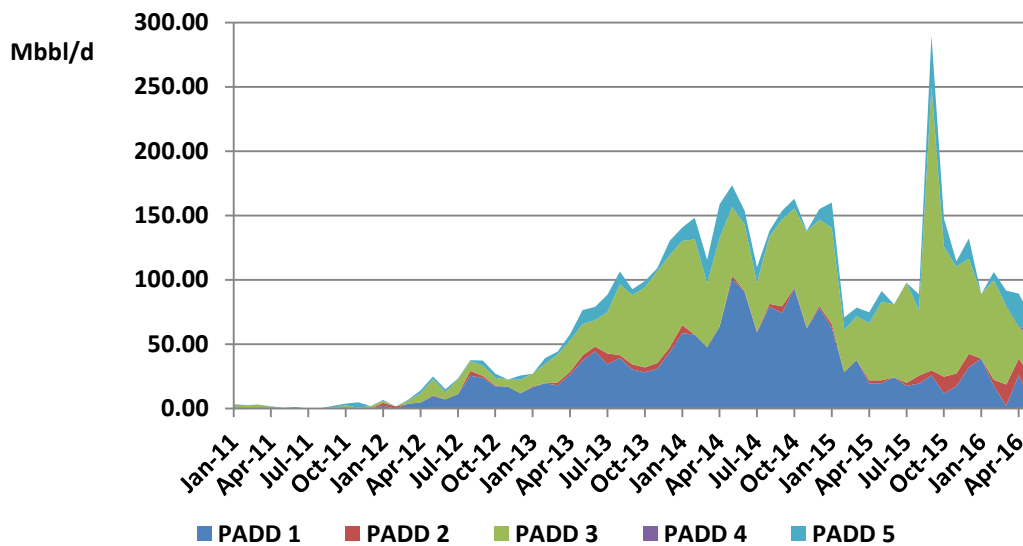
The following section begins with a discussion of crude-by-rail movements and capacity in North America, and ends with a comparison of the economics of crude-by-rail versus pipelines.

B.3.1 North American Crude-by-Rail Movements

Since 2011, exports of crude oil by rail from Canada to the U.S. have increased substantially, from an average of about 2,200 bbl/d in 2011 to approximately 119,000 bbl/d in 2015. Crude-by-rail export volumes peaked at nearly 290,000 bbl/d in September 2015, and declined to nearly 70,000 bbl/d in May 2016 (27).

While crude-by-rail exports from Canada were initially spread fairly evenly between PADD 1 and PADD 3, the destination for exports shifted towards PADD 3 in 2015, with a more even distribution in the first five months of 2016. These figures do not include crude-by-rail volumes transported within Canada (Figure 3).

Figure 3 - Canadian Crude-by-Rail Exports by PADD, monthly 2011-2016



Source: U.S. Energy Information Administration, Crude Oil Movements of Crude Oil by Rail (27)

Several Canadian refineries and ports have installed or expanded crude-by-rail offloading capacity including Suncor Energy Product Partnerships’ Montreal refinery (35,000 bbl/d), Valero’s Jean-Gaulin

refinery in Lévis (60,000 bbl/d), Irving's Saint John refinery (200,000 bbl/d), Chevron's Burnaby refinery (7,000 bbl/d), and the Sorel-Tracy terminal (33,000 bbl/d)^{ix}.

Crude-by-rail use grew even more quickly in the U.S. where expansion was driven by production growth in remote regions which were underserved by pipelines. For example, crude-by-rail movements from PADD 2 (Midwest) increased from an average of approximately 91,000 bbl/d in 2011 to 632,000 bbl/d in 2015 as a result of tight oil production growth from the Bakken fields in North Dakota. In recent months, crude-by-rail shipments in the U.S. have declined. This is a result of low crude oil prices which have led to decreases in output from some U.S. shale oil basins as well as more pipeline capacity being added from some basins (28).

B.3.2 North American Crude-by-Rail Loading & Offloading Infrastructure

A key question when considering if crude-by-rail is a viable alternative to pipelines is whether rail infrastructure could support significant crude-by-rail growth (e.g., a sufficient supply of tanker cars, the costs associated with enhanced safety regulations and requirements for crude-by-rail transportation, etc.). Infrastructure growth has been strong to date, and there is historical precedent for such growth. For example, the U.S. Department of State's *Final Supplemental Environmental Impact Statement for the Keystone XL pipeline* (KXL FSEIS) outlines the development of rail transport infrastructure and services from a coal basin as a precedent for the possibility of rapid railway expansion (29). Furthermore, the expansion of crude-by-rail capacity in the U.S. is illustrative of the rate and level of potential rail infrastructure development when market factors create the incentive for this investment.

Crude-by-rail loading capacity from the WCSB has expanded significantly in the past five years. While traditionally it was employed primarily by smaller crude oil producers, crude-by-rail served as an alternative for companies as pipeline constraints and price differentials increased. Estimates indicate that crude-by-rail loading capacity in Alberta and Saskatchewan is 1.1 MMbbl/d (30)^x. In the U.S., crude-by-rail offloading capacity is concentrated in PADD 1 and PADD 3. Recent estimates from RBN Energy indicate that nearly 1.7 MMbbl/d of rail offloading capacity currently exists in PADD 3 (31). The KXL FSEIS estimated that rail offloading capacity in PADD 1 was nearly 1 MMbbl/d in 2013 (29). Estimates from the U.S. Dept. of State indicate that PADD 2 had around 50% of total U.S. crude loading capacity in 2013, at 1.6 MMbbl/d, concentrated in the Bakken fields of North Dakota (28) (29).

Crude-by-rail capacity figures are not directly comparable with pipeline capacity figures. When bitumen is produced, it is either upgraded to synthetic crude oil (typically production from oil sands mines) or blended with a diluent to enable it to flow on a pipeline. The volume of diluent blend can vary, but is typically around 30% of a barrel of diluted bitumen. For diluted bitumen, since the diluent is blended with the bitumen for transport, producers also pay to ship the associated diluent to market, reducing the amount of pipeline space available for bitumen.

^{ix} Figures compiled from news sources and discussions with the NEB.

^x The Department of State KXL FSEIS Market Analysis notes a report from the Industrial Commission of North Dakota (2013) that cites effective rail capacity at around 80% of nameplate capacity.

Rail cars can haul oil sands blends with a lower proportion of diluent which reduces the costs per barrel of bitumen transported and decreases the financial impact of differences in diluent value between the origin and destination markets (32). Alternative bitumen blends hauled on rail are *railbit* (15-20% diluent) or *rawbit* (0-2% diluent). Transporting *rawbit* requires special tanker cars and loading and offloading facilities which are not widely used at this time (32).

B.3.3 Relative Costs of Pipelines and Rail

This review presents scenarios (see below in B.4) that include a baseline scenario in which crude-by-rail is the primary transportation option available to move oil sands production growth to market, and two additional scenarios with varying pipeline construction assumptions. Under the baseline scenario, it is assumed that the primary market for Canadian production growth would be PADD 3 (Gulf Coast), in the absence of further pipeline capacity being built from Western Canada. This assumption is supported by the considerations noted above that PADD 3 is a large refining market, with significant heavy oil refining capacity and scope to process greater volumes of Canadian crude oil, and with a large amount of rail offloading capacity. For scenarios in which the Line 3 replacement pipeline is built, it is assumed that PADD 3 is also the primary market for oil sands production growth.

The cost difference between crude oil pipelines and rail is a primary consideration as to whether the construction of additional pipeline capacity could result in greater crude oil production, and therefore greater upstream GHG emissions in Canada. If rail costs are sufficiently high relative to pipeline transportation costs, the return on future oil sands projects that have no other option but to use rail would be expected to be lower and these projects may not be built in the absence of new pipelines.

In *EF 2016*, the NEB estimates that the cost difference between shipping a barrel of bitumen to the U.S. Gulf Coast on rail and shipping via pipelines would be USD 10/bbl. This is consistent with the KXL FSEIS which estimated a cost difference of up to USD 9/bbl (depending on the diluent content). This is an upper threshold since the relative cost of rail would decrease if a company reduced the amount of diluent blended with the bitumen or had negotiated lower rates of transport via rail. The KXL FSEIS estimated that the additional cost to rail *rawbit* was between USD 0-3/bbl relative to pipelines while the additional cost to transport *railbit* was between USD 5-7/bbl relative to pipelines. Also, it is important to consider that these cost estimates do not incorporate tax or royalty considerations, which would decrease the relative difference in transportation costs in after-tax terms. Finally, the cost difference is also a high-end estimate since it assumes that the difference in transportation costs for Canadian producers remains static over the long term, which is unlikely. For example, companies may choose to use some combination of rail, pipeline and barge transportation to move barrels from Western Canada if no additional pipeline capacity were built which could further lower transportation costs under a no-pipeline scenario.

Even with a cost difference, there are some advantages to rail including greater flexibility in destinations and shorter transport times between the same destinations. Other benefits are discussed in CAPP's 2015 crude oil forecast (8). As a result, even when sufficient pipeline capacity is available, it is expected that there will still be crude being transported via rail, although this quantity would likely be small.

B.4 Incremental Emissions and Pipeline Capacity Additions

This section provides a discussion of the conditions under which constructing the Line 3 replacement pipeline could lead to higher Canadian oil sands production growth and associated emissions. It considers two scenarios: 1) no additional pipeline capacity from 2015 capacity levels is built besides the Line 3 replacement pipeline, and 2) other additional pipeline capacity as well as the Line 3 replacement pipeline is built such that shipping large volumes of crude-by-rail is no longer needed^{xi}. The baseline to compare to each of these scenarios would be one in which no additional pipeline capacity would be added and any production growth is shipped by rail. The key difference between these scenarios and the baseline is the expected cost of transporting the marginal barrel of oil sands production from the WCSB.

The conclusions from these scenarios are driven by the degree to which the netback price for the marginal barrel of oil sands production could be affected^{xii}. As illustrated below, incremental oil sands production could be enabled if the cost of transporting the marginal barrel of oil sands decreases, increasing the netback price of the marginal barrel of oil sands between the baseline scenario and the pipeline scenarios. An increase in netback price would improve the profitability of future oil sands projects and increase the likelihood of incremental production.

B.4.1 Baseline: No new pipeline capacity built from WCSB

Under the baseline, no new pipeline capacity is built and oil production currently transported via rail or under construction would be transported by rail. If future projects are expected to be sufficiently profitable when transporting crude-by-rail, they would proceed in the baseline. The netback price in Alberta for the marginal barrel of oil sands production would be the benchmark price (e.g., Western Canadian Select for heavy sour crude oil), less the cost of transportation by rail.

B.4.2 Scenario 1: The Line 3 replacement pipeline is the only new pipeline capacity built

In a scenario where the Line 3 replacement pipeline is built, but no other additional pipeline capacity from the WCSB is built, there are two potential outcomes: **1A)** the netback price of the marginal barrel of oil sands could remain the same as under the baseline scenario, or **1B)** it could increase relative to the baseline.

1A) A portion of the oil sands production growth currently under-construction and/or some portion of crude oil export volumes currently transported by rail could shift to the additional pipeline capacity (370,000 bbl/d) available on the Line 3 replacement pipeline. Since more production capacity is under construction than could be carried on the Line 3 replacement pipeline, the marginal barrel of oil sands produced would be expected to move by rail regardless of whether the pipeline is built. Under these circumstances, the netback price for the marginal barrel of oil sands in Alberta may not change.

If that were the case, the construction of the Line 3 replacement pipeline would not result in *incremental* production in Canada because the decision to produce an additional barrel from the oil sands would be based on the same netback price both with and without the Project.

^{xi} Some volumes may still flow by rail under this scenario, but it is assumed that this would be for reasons related to small producers not being able to achieve economies of scale for pipeline access.

^{xii} The netback price of oil in Alberta is the market price less the transportation costs associated with shipping the next barrel of oil.

1B) It is possible that the netback price of the marginal barrel of oil sands production could increase if the Line 3 replacement pipeline were the only pipeline capacity built from Western Canada. For example, building a pipeline could alter the end-markets for some types of crude oil, changing the marginal cost of transportation, or improving the overall efficiency of the North American crude oil transportation network. These examples could result in lower transportation costs, higher crude oil netback prices for the marginal barrel of oil sands production, and improved financial performance for future oil sands projects. In this case, the Line 3 Replacement Program could enable incremental production and upstream emissions. A more complex quantitative examination of the issue would be required to model whether any of these circumstances could occur if the Line 3 replacement pipeline were built.

B.4.3 Scenario 2: The Line 3 replacement pipeline and other pipeline capacity is built

If the Line 3 replacement pipeline and other pipelines are built such that large-scale rail shipments of crude oil were no longer needed to transport the marginal barrel of oil sands production, then the netback price of the marginal barrel of oil sands production would increase. Previously unprofitable oil sands projects could become profitable resulting in an increase in production and upstream GHG emissions relative to the baseline. However, attributing any particular portion of these incremental upstream emissions to the Line 3 Replacement Program, or any specific pipeline project, would be difficult. Rather, it would be attributable to the overall expansion of the Canadian pipeline transportation system.

To understand the degree to which incremental production could be added as a result of additional pipeline capacity under these scenarios (i.e., Scenario 1B, and Scenario 2), it is necessary to examine the economics of new investments in the oil sands.

B.4.4 Oil Sands Supply Costs and Additional Costs from Crude-by-Rail

Analysts often use a metric referred to as the supply cost to compare and assess the financial feasibility of proposed projects. For oil sands projects, this is the constant dollar price of oil that is required to recover all capital and operating costs, transportation costs, taxes, and royalties, and earn a rate of return on investment (usually 10-15%). Supply costs are directly related to the netback price received in Alberta. If the netback goes up, the supply cost decreases, and vice versa.

For ease of comparison, supply costs are usually adjusted to a benchmark crude oil hub price, such as WTI or Brent, and reported in U.S. dollars. For the purposes of this review, supply cost estimates are benchmarked to Canadian light oil at Edmonton, Alberta and presented in USD terms. The netback price in Alberta is a key input in determining the supply cost, with lower transportation costs resulting in lower supply costs.

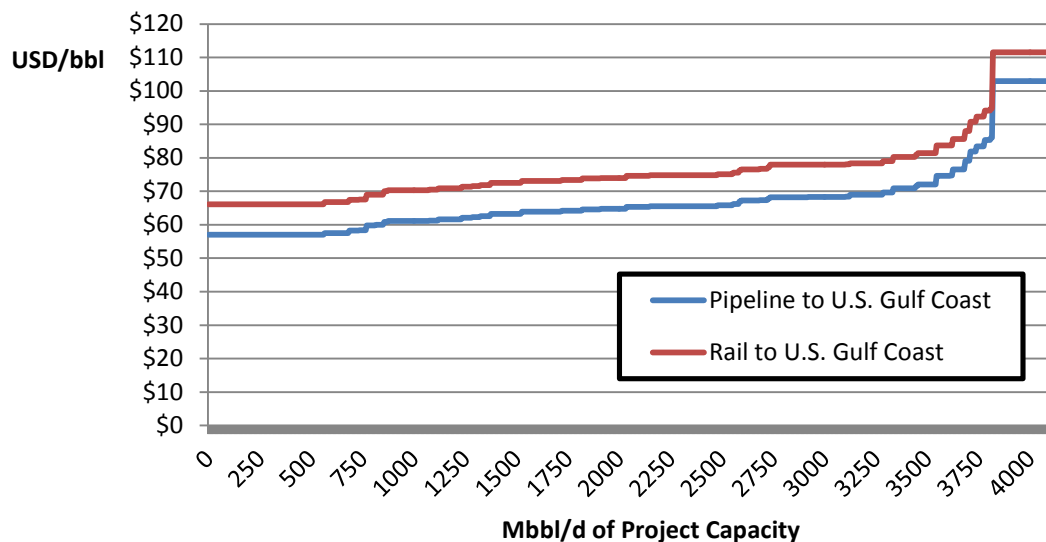
A survey of various sources that regularly publish oil sands supply cost estimates reveals a range of estimates for oil sands projects with differences in supply costs driven by the type of project (*in situ* vs. mining) and the modelling assumptions (33) (34). *In situ* project supply costs range between USD 45/bbl and 80/bbl WTI equivalent while mine project supply costs range between USD 80/bbl and 90/bbl WTI

equivalent^{xiii}. The lower end of the range typically represents expansions at existing facilities and the higher end represents new projects. Key differences in supply costs result from assumptions around exchange rate, energy use, capital costs, and price differentials. While they are left constant for the purposes of this analysis, it is important to consider that supply costs are not static, and are likely to change over time as market conditions evolve. For example, recent analysis from IHS indicated that oil sands supply costs decreased by as much as USD 10/bbl between 2014 and 2015 owing to lower construction costs resulting from the recent oil price decline, and lower natural gas costs (21).

To assess the impacts of transportation options on oil sands supply costs, ECCC uses a supply curve generated from its in-house oil sands project model. The supply curve is based off of publicly available information on over 125 *in situ* oil sands project phases that have been announced, are awaiting approval or have been approved by the Alberta Energy Regulator (referred to as *potential in situ* oil sands capacity), but are not under construction or currently operating. These projects are expected to be sources of supply growth in the oil sands post-2020.

The supply curve indicates that a substantial amount of potential *in situ* oil sands project capacity has supply costs that range between USD 50 and 70/bbl assuming pipeline transportation to PADD 3 (see Figure 4). Based on the incremental cost estimates for transporting crude oil by rail above (+USD 10/bbl), it is expected that the supply cost range for a large amount of planned projects post-2020 would be between around USD 60 and 80/bbl where producers used rail to PADD 3 rather than shipping diluted bitumen via the Line 3 replacement pipeline to PADD 3 (i.e., the baseline scenario)^{xiv}.

Figure 4 - Oil Sands Supply Curve for Unsanctioned *In Situ* Projects



Source: ECCC Oil Sands Supply Model

^{xiii} Integrated mining projects are not discussed in this piece because few new integrated mining projects are planned at this time.

^{xiv} Key assumptions (exchange rates, price differentials) that drive the oil sands model were taken from the NEB (10). Other assumptions include a long run steam-to-oil ratio (SOR) of 3 for projects, average variable operating costs of \$12/bbl of bitumen, sustaining capital costs of \$6.50/bbl, a required rate of return of 12% (nominal), cost and commodity price inflation of 2% per year, no cogeneration at facilities, an average utilization rate of 75%, and Alberta's climate policy at \$30/tonne CO₂ eq (nominal) on 20% of emissions.

B.4.4.1 Comparing a Supply Curve to a Production Forecast

The supply curve represents a rank ordering of potential oil sands projects that could be developed in the future. While the ECCC oil sands supply curve indicates potential *in situ* project capacity of up to 4 MMbbl/d, this does not mean that all of these projects will come online.

The feasibility of developing the full 4 MMbbl/d of potential oil sands capacity is limited by the considerable amount of capital and labour required to construct and operate the facilities. Historically, increased development in the oil sands has led to capital and operating cost inflation that drove up supply costs and dampened the returns on future investment. As well, the attractiveness of individual projects depends on world oil demand, crude oil prices, and the prospects for competing alternative investments. As such, many of the projects included in ECCC's oil sands supply curve will likely remain undeveloped.

Remodeling the supply curve to reflect the difference in transportation costs between rail and pipeline to PADD 3 is done to illustrate the change in costs, but should not be interpreted as the Line 3 Replacement Program lowering the supply costs of all potential *in situ* projects in the future. In effect, this transportation cost impact may only be realized by a few oil sands projects.

While the change in netback price for the marginal barrel of oil sands production influences whether adding pipeline capacity would cause incremental production, the expected price of crude oil influences the degree of incremental production and upstream emissions.

B.4.4.1.1 Low Prices

If long-term Canadian light oil prices were below USD 60/bbl in real terms, there is unlikely to be substantial oil sands production growth post-2020 without a significant decrease in production costs from current levels, regardless of whether transportation was by rail or pipeline. An example of this low growth is the *EF 2016 Low Price Case* discussed above that has WTI prices growing to only USD 60/bbl by 2025, and only USD 76/bbl by 2040. In this case oil production only grows by approximately 150,000 bbl/d after projects currently under construction are completed (i.e. after 2020), even when pipeline capacity is available.

Given the challenged project economics at such prices, it is not expected that the availability of pipeline transportation would improve profitability sufficiently such that a company would decide to proceed. As a result, if Canadian light oil prices were below USD 60/bbl, building pipeline capacity would not be expected to result in additional oil sands development.

B.4.4.1.2 Mid-Range Prices

If long-term Canadian light oil prices were between USD 60 and 80/bbl in real terms, the cost savings that arise from the ability to transport crude via pipeline could enable oil production growth that would not have otherwise occurred.

All else being equal, supply cost estimates indicate that a considerable amount of potential *in situ* oil sands production capacity could become profitable (~3.3 MMbbl/d) that may not have been profitable when rail was the only transportation option in the baseline. As defined previously, any production that

would not have occurred in the baseline scenario, but may occur if the Line 3 Replacement Program and other pipeline projects are completed, is considered to result in incremental upstream GHG emissions. Therefore, if long-term oil prices were in this range, some production growth could be incremental. If incremental rail costs are lower than the USD 10/bbl estimated transportation difference, the amount of incremental production and associated incremental upstream GHG emissions would be lower.

B.4.4.1.3 High Prices

If longer term Canadian light oil prices were greater than USD 80/bbl in real terms, a number of projects would likely be strongly profitable and a large amount of oil sands growth would be expected to occur regardless of whether the oil was moved by pipeline or rail. However, upstream project economics would be further improved if pipeline transportation options were available at higher oil prices. As put forward in the NEB’s *EF 2016 Constrained Case*, the cost savings provided by pipelines could result in increased cash flow available for re-investment and, over time, increased production which would likely increase upstream GHG emissions. In reality, this effect may be minimal given the availability of capital in global financial markets (i.e., companies do not need to rely on internally generated cash flow to support capital investment). As such, incremental production is expected to be minimal at light oil prices above USD 80/bbl compared to a scenario where prices are in the USD 60-80/bbl range.

B.4.4.2 Incremental Emissions and Third-Party Studies

Given the significant number of oil sands projects that could become economic with prices between USD 60 and 80/bbl there is greater potential for incremental production resulting from pipeline construction if long term prices were in that range (see Table 7).

Table 7 - Potential Incremental Oil Sands Production in Canada

	Price		
	<\$60	\$60-80	>\$80
Oil Sands Growth	Limited to no growth in oil sands production	Limited growth in oil sands production	Growth in oil sands production
<i>Incremental</i> GHG Emissions as a result of pipelines	Less Likely	Potential	Minimal
Potential <i>cumulative</i> oil sands supply with a supply cost in the price range (post-2020)	~0 MMbbl/d	~3.3 MMbbl/d	~4.1 MMbbl/d

Source: ECCCC Oil Sands Supply Cost Model

Several reports and studies have examined the GHG impacts of various pipeline projects. These studies have included an assessment of, or an assumption to inform, the amount of incremental production that could result from building a pipeline project. However, no report has specifically examined the upstream GHG implications of the Line 3 Replacement Program. These reports illustrate that whether pipelines are

shown to cause incremental crude oil production is largely determined by the assumptions guiding the analysis, including those related to the availability and cost of crude-by-rail, the potential for other crude oil pipelines to be built, oil price and other factors.

Reports from Navius Research have examined the greenhouse gas impacts of the Energy East and Trans Mountain Expansion pipelines. These reports provide estimates of the incremental crude oil production that could occur as a result of building these pipelines, ranging between 3% and 9% of proposed pipeline capacity for Energy East, and 11% and 29% of pipeline capacity for the Trans Mountain Expansion pipeline (35) (36). Furthermore, the *EF 2016's Constrained Pipeline Scenario* provides insight into the potential for incremental production from the addition of a number of new crude oil pipelines. NEB figures indicate that *incremental* production as a result of building pipelines would be an increase of between 8% and 17% in 2040, depending on assumptions of additional pipeline capacity (10).

A number of other studies have analyzed upstream emissions from crude oil pipelines, but have typically made assumptions about the degree to which the projects could cause incremental production. These assumptions have ranged between 0% and 100% and have varied based on the factors noted above.

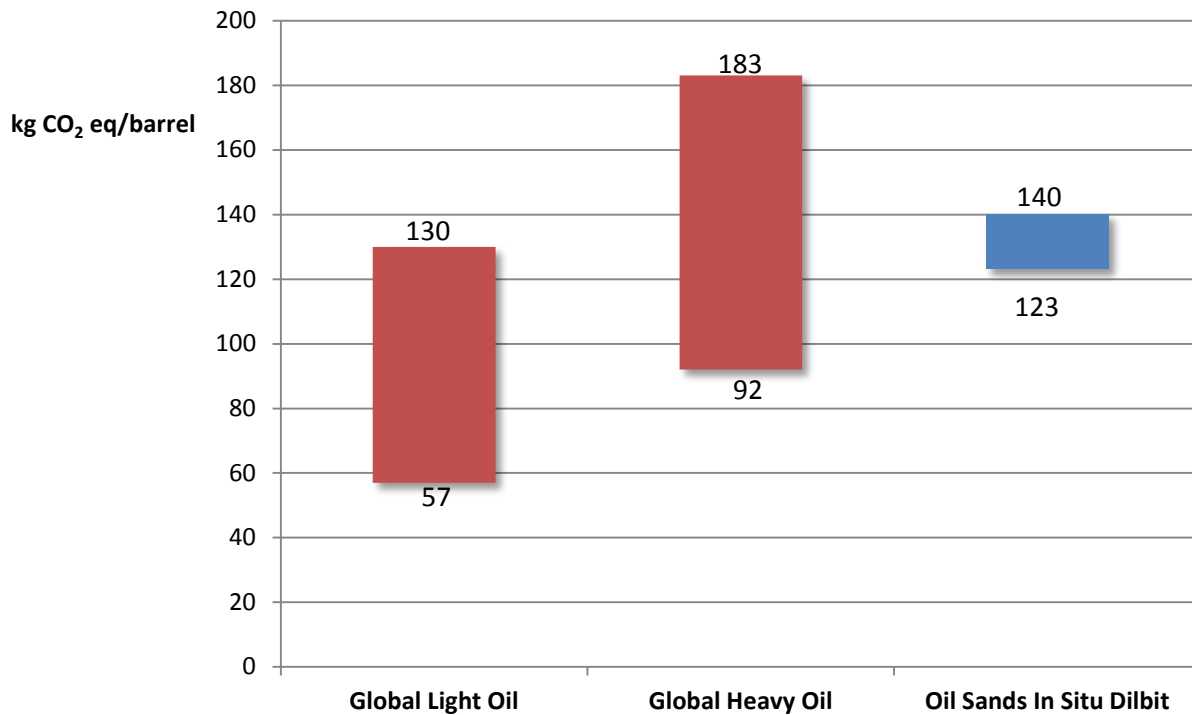
B.4.5 Global Oil Consumption and Upstream GHGs

If additional pipeline capacity in Canada were to enable incremental Canadian production growth, this could have two impacts on global crude oil markets: 1) it could displace different types of oil that would no longer be produced, or 2) it could add to the overall global supply at a given price, which could result in a slightly lower global crude oil price, and greater global crude oil consumption over time.

Where incremental oil sands production displaces other crude oil production that would have been produced in the baseline, the global GHG emissions impact would be the difference in well-to-tank (WTT) emissions between oil sands production and the crude oil that was displaced. A report from IHS Cambridge Energy Research Associates (CERA) argued that oil sands production on the proposed Keystone XL pipeline would have merely displaced other heavy oil, typically with comparable WTT emissions, resulting in a small impact to global emissions (37). While this conclusion is logical when discussing conditions in the PADD 3 market and U.S. emissions impacts, the global impact on emissions would depend on the type of crude oil that would no longer be produced globally.

Comparing WTT data from IHS CERA for a variety of crude oil types illustrates the wide range of potential emissions impacts. IHS estimates that WTT emissions are 57 to 130 kg CO₂ eq per barrel for light crude oil, 92 to 183 kg CO₂ eq per barrel for other types of global heavy crude oil, and 123 to 140 kg CO₂ eq per barrel for oil sands *in situ* dilbit (Figure 5).

Figure 5 - Well-to-Tank GHG Emission Intensity Ranges by Type of Crude Oil^{xv}



Source: IHS CERA

Where incremental Canadian oil sands production leads to an increase in global oil supply, the accompanying decrease in global crude oil prices could have an impact on global crude oil consumption. The global GHG emissions impact with this effect would be the total lifecycle emissions of oil sands in situ dilbit, from well-to-wheels (WTW). WTW data from IHS CERA indicate that WTW GHG emissions from oil sands in situ production range between 508 and 525 kg CO₂ eq per barrel of production.

A comprehensive report on the proposed Energy East pipeline by Navius Research found that, although the majority of incremental production would displace existing global supply, it is the potential increase in global consumption that would likely have a larger impact on global emissions. The report found that, even with only a slight increase in total global crude oil supply, the effect of lower global oil prices increasing consumption over time led to 74% to 87% of the net emissions impact of the proposed Energy East pipeline in 2035 (38). The magnitude of this impact, relative to the impact in which other types of crude oil are displaced, is logical since tank-to-wheel emissions from combustion represent between 70% and 80% of the total WTW GHG emissions (39).

Given that the effect of incremental Canadian oil sands production on global supply can have a large impact on global emissions, it is important to consider circumstances influencing the degree to which it

^{xv} Global light oil includes Eagle Ford, North Sea Forties, Arab Light, Bakken Blend, Kirkuk, Basrah Light, Bonny Light, and Alaskan North Slope. Global heavy oil includes Venezuela Petro Zuata, Venezuela Boscan, Venezuela Bachaquero, Mexico Maya, North Sea Mariner, and Brazil Marlim.

displaces existing sources of, or adds to total, global crude oil supply. The magnitude of the increase in global oil supply depends on the slopes of the global supply and demand curves at the point of equilibrium. In general, the more elastic the global supply curve (i.e., the flatter the crude oil supply curve or the more oil available within a given price range), the higher the proportion of incremental oil sands production that would be expected to displace other types of crude oil, and vice versa. This is logical since an elastic supply curve implies that the quantity produced is highly sensitive to changes in price. In addition, the higher the elasticity of demand for crude oil, the higher the proportion of incremental oil sands production that would be expected to add to total global oil supply (40).

As previously stated, there is greater potential for incremental oil sands production at crude oil prices between USD 60 and 80/bbl. Global oil supply curve studies generally show a large amount of global oil production potential in this price range. For example, in an analysis of future oil projects that have not received a final investment decision, Wood Mackenzie showed that oil sands projects are similar in cost to 13 MMbbl/d of other types of production (41). In an analysis of the 420 largest global oil projects, Goldman Sachs expects nearly 30 MMbbl/d of crude oil production capacity with supply costs in the range of USD 40-80/bbl (42).

With a considerable amount of potential global oil supply available at prices below USD 80/bbl, a large proportion of any incremental oil sands production would be expected to displace other types of crude oil production, rather than add to total global oil supply. Given the comparable WTT emissions noted above between different types of crude oil, it is likely that there would only be small net change in global GHG emissions based on the WTT difference. The total global GHG impact would be larger if a larger portion of incremental oil sands production were expected to add to total global oil supply, or if global demand were assumed to be highly elastic^{xvi}.

B.5 Conclusions

The analysis in Part B provides insight into the conditions under which building the Line 3 replacement pipeline could lead to incremental GHG emissions in Canada. The key elements affecting this discussion are the expected long-term price of crude oil, oil sands supply costs, the availability and relative cost of crude-by-rail, the effect on the netback price of oil sands in Alberta, and assumptions around total pipeline capacity that could be built. In summary, the discussion finds that:

- *If the Line 3 replacement pipeline is the only pipeline capacity added from Western Canada, there would be no incremental production and upstream emissions if the netback price for the marginal barrel of oil sands production was unaffected. This could occur because oil sands production already expected to be completed by 2019, as well as volumes currently transported by rail, would be more than sufficient to fill the Line 3 replacement pipeline. However, increased pipeline network efficiency or differing assumptions could alter this conclusion.*

^{xvi} A range of demand elasticities are assumed in Erickson and Lazarus (2014) while demand elasticity sensitivities were examined by Navius Research in their analysis of the Energy East pipeline project.

- *If additional pipeline capacity, including the Line 3 replacement pipeline, is built such that shipping crude-by-rail was no longer needed, a portion of the emissions calculated in Part A could be incremental.*
- The extent of incremental production and emissions under either scenario depends on the long-term price of Canadian light oil.
 - At prices lower than USD 60/bbl, most planned oil sands projects not yet under construction would likely be unprofitable and would not be built, meaning there is unlikely to be incremental emissions.
 - At prices of USD 60-80/bbl, many potential projects could become profitable with pipeline access. However, the amount of incremental production that would come online is uncertain.
 - At prices greater than USD 80/bbl, many potential oil sands projects would be profitable and have a higher likelihood of being built, even if rail were the only transportation option. However, the cost savings provided by pipelines could result in some increased investment and production, although at a lower level than if oil prices were in the USD 60-80/bbl range noted above.
- If additional pipeline capacity resulted in incremental oil sands production, there could be an impact on global supply and prices. Incremental production would either displace other sources of crude oil at the margin, or add to total global supply. Where it displaces other types of crude oil, the impact on global emissions would be the difference in well-to-tank GHG emissions. Where it adds to total global oil supply, lower global prices and increases in the quantity of oil demanded would increase emissions based on the full well-to-wheels lifecycle emissions.
- Given that a substantial amount of global crude oil supply is financially viable in a similar crude oil price range to Canadian in situ oil sands, it is expected that the largest portion of incremental production would displace other types of crude oil.

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Annex A – Proportions of Crude Oil Categories for the Future Mix

Year	Conv. Light (%)	Conv. Heavy (%)	CSS Heavy (%)	SAGD Heavy (%)	Mined Bitumen (%)	Synthetic Crude (%)
2019	15	18	8	22	8	29
2020	15	18	8	23	7	29
2021	14	17	8	24	7	29
2022	14	17	8	25	7	28
2023	14	17	8	26	7	28
2024	14	16	9	27	7	27
2025	14	15	9	28	8	27
2026	14	15	9	29	8	26
2027	14	15	9	29	8	26
2028	14	15	9	30	8	25
2029	13	15	9	31	7	25
2030	13	14	9	31	7	25

Annex B – Emission Factors Methodology

Emission factors were developed for categories of crude oil expected to be transported by the Line 3 replacement pipeline, including crude oil produced from different production and processing operations and diluents that assist the movement of heavier crude oil. The emission factors reflect changes in the emission intensity of the activities associated with the extraction and processing of crude oil over time. The emission factors take into account all on-site sources of emissions associated with production and processing including combustion, flaring, venting, and fugitive.

General Approach to Crude Oil Emission Factors

ECCC has developed emission projections for future years for the different crude oil categories. These are presented in *Canada's Second Biennial Report on Climate Change* (9) for the period to 2030. The level of emissions associated with each crude oil category is a function of:

1. The extent of the production activity, and
2. The expected changes to the emission intensity associated with that crude oil category.

The expected future demand and resulting production activity for the crude oil categories comes from the NEB's *with current measures* reference scenario (10). The expected changes over time to the emission intensity of the activities associated with the extraction and processing of crude oil are a function of environmental policy and technology implementation. The emissions and production projections used by Environment and Climate Change Canada for this review include the estimated future impacts of existing policies and measures that have been implemented as of September 2015. Projections of emissions estimates for onshore conventional light and heavy crude oil, oil sands production by cyclic steam stimulation (CSS) and steam-assisted gravity drainage (SAGD), and mined bitumen were used. The projections also include assumptions around energy efficiency and other improvements at oil and gas facilities. The combination of the emissions and production projections allows for the calculation of unique annual emission intensities associated with the extraction and processing of different categories of crude oil to 2030.

Synthetic Crude Oil Emission Factor

Synthetic crude oil (SCO) is an intermediate product that is obtained from heavy crude oil produced by conventional means, CSS, SAGD, and mined bitumen production methods. Each production method has a unique range of emission intensities representing the particular technology and operations to produce a barrel of oil. The process of producing SCO is called *upgrading*. The SCO emission factor used in the estimates of upstream emissions associated with the Line 3 Replacement Program takes into account the emissions associated with both the production of heavy crude oil or bitumen to be upgraded, and the emissions associated with the upgrading activity itself. The calculation of the SCO emission factor for a given year requires a two-step process, which is outlined below.

Only portions of the crude oil produced in Canada is upgraded domestically. Based on historical records, most of the mined bitumen is upgraded in Canada while only smaller portions of heavy crude oil produced by CSS, SAGD, and conventional methods is upgraded in Canada. The NEB provides projected

amounts of heavy crude oil produced by conventional methods, mined bitumen, and *in situ* oil sands production that are upgraded domestically in future years (10). The *in situ* oil sands production includes production using CSS and SAGD methods, where 25% of the volume was allocated to CSS and the remaining 75% to SAGD. To calculate an emission factor, the emission intensities corresponding to each crude oil category were multiplied by the proportional contribution of that category to the total volume upgraded. The proportion of upgraded crude oil in each category was determined by dividing the volume of upgraded crude oil in that category by the total volume upgraded. The following equation shows the calculation for the emission factor, in units of emissions per barrel.

$$EF_{Upgrader\ Feed} = \sum_i (P_i * EI_i)$$

Where,

- i is the crude oil category,
- P_i is the volume of the crude oil in category i that is upgraded divided by the total volume of all crude oil categories that is upgraded
- EI_i is the emission intensity for the production of crude oil in category i

Based on discussion with the NEB, the production of a barrel of SCO requires, on average, upgrading 1.1 barrels of crude oil. To convert the emission factor for upgrader feed from units of emissions per barrel of crude oil product into units of emissions per barrel of SCO, the emission factor ($EF_{Upgrader\ Feed}$) was adjusted by multiplying it by 1.1.

To determine the emission factors associated with the activity of upgrading, the emissions resulting from upgrading were divided by the amount of SCO produced. The emissions associated with upgrading were obtained from the underlying data of *Canada's Second Biennial Report on Climate Change* (9), and the production of SCO was obtained from the NEB (10).

The overall emission factor for the production of SCO is the sum of the emission factor ($EF_{Upgrader\ Feed}$) and the emission factor associated with upgrading ($EF_{Upgrading}$), as outlined in the equation below:

$$EF_{SCO} = EF_{Upgrading} + EF_{Upgrader\ Feed} * 1.1$$

Emission Factors Determined Using Facilities Reported Data

Emission factors associated with the production of crude oil (including SCO) by CSS, SAGD, and bitumen mining methods can also be determined using facility-reported emissions and production data. Large oil production and processing facilities exceed provincial and federal thresholds for annual GHG emissions reporting. The reporting requirements of the federal *Greenhouse Gas Reporting Program* (GHGRP) and provincial reporting regimes such as the *Specified Gas Emitters Regulation* (SGER) in Alberta capture the majority of the emissions from the aforementioned production methods for those crude oil categories. The level of production from each facility was obtained from provincial reporting sources (e.g. Statistical Reports ST 53 and ST 39 from the Alberta Energy Regulator).

Facility-level emissions and production are available for historic years up to and including 2014. The type of production operations occurring at a facility is usually reported. Some facilities produce a single

product, while others produce SCO in addition to non-upgraded crude oil. Facilities producing upgraded as well as non-upgraded crude oil are called *integrated facilities*. They can upgrade products from their own production or from other facilities to produce SCO. In integrated facilities, the emissions associated with the non-upgraded production are difficult to segregate from the emissions associated with the production of SCO. ECCC has developed a method to segregate the emissions associated with the production of non-upgraded products and with the upgrading activities for each integrated facility in Canada. In general, ECCC has assumed a 40% share of emission from mining activities and a 60% share for upgrading activities at an integrated facility (based on the natural gas requirements of separate mining and upgrading activities from CERI Study No. 119, Part II – *Oil Sands Supply Cost and Production*). These proportions, however, are subject to the fuel use constraints imposed by Statistics Canada Report on Energy Supply and Demand and Canada’s GHG Inventory. Using these proportions the total emissions from integrated facilities were disaggregated into crude oil production and upgrading emissions.

The 2014 emission factors for each crude oil category and for the upgrading activity was determined by aggregating emissions from facilities producing similar crude oil and dividing this by their aggregated production, as per the following equation:

$$EF(\text{facil})_{i,2014} = \frac{\sum_{j=1}^n \text{Emissions}_j}{\sum_{j=1}^n \text{Production}_j}$$

Where,

- i is the crude oil category (CSS, SAGD, mined bitumen, and SCO),
- j is a facility with i^{th} production or upgrading activity,
- n is total number of facilities with i^{th} production or upgrading activity, and
- $EF(\text{facil})_{i,2014}$ is the emission factor representing i^{th} product or upgrading activity for the year 2014.

Estimates of emission factors for future years were calculated based on the changes projected for the emission factors using data from *Canada’s Second Biennial Report on Climate Change* (9) and the NEB report *Canada’s Energy Future 2016 – Energy Supply and Demand Projections to 2040* (10). Information regarding changes in emissions intensities for future years were obtained from the calculated emission factors for projected years determined in the *General Approach to Crude Oil Emission Factors* section of this Annex. Similarly, the projected changes in the upgrading emission factor were obtained from following the approach in the *Synthetic Crude Oil Emission Factor* section. The proportion of change in the projected emission factors was determined by dividing the emission factor for a given projected year by the emission factor for the year 2014, as per the following equation.

$$PC_{i,t} = \frac{EF_{i,t}}{EF_{i,2014}}$$

Where,

- i is the crude oil category (CSS, SAGD, mined bitumen, and SCO),
- t is an applicable projected year,

- EF is the emission factor as determined by the methodology in the *General Approach to Crude Oil Emission Factors* and *Synthetic Crude Oil Emission Factor*, and
- PC is the proportion of change in the projected emission factor.

The 2014 emission factors determined from the facility-reported data were then multiplied by the proportion of change for the applicable projected years in order to develop projected emission factors that are based on facilities reported data.

$$EF(\text{facil})_{i,t} = PC_{i,t} * EF(\text{facil})_{i,2014}$$

Where,

- *i* is the product type of CSS, SAGD, mined bitumen, and SCO,
- *t* is an applicable projected year,
- PC is the proportion of change in the projected emission factor, and
- EF(facil) is the emission factor developed based on facility reported data.

Diluent Production Emission Factors

Heavier crude oil requires that it be blended with diluent to facilitate its movement through a pipeline. The type of and quantity of heavy crude oil being transported will impact the quantity of diluent required. The proportion of diluent needed for blending varies for different categories of heavy crude oil. The following table provides the volume proportions of diluent needed.

Crude Oil Category	Diluent Proportion
<i>Conventional Heavy</i>	8%
<i>CSS Heavy</i>	30%
<i>SAGD Heavy</i>	30%
<i>Mined Bitumen</i>	20%

The volume of diluent production projection is obtained from the NEB's *with current measures* reference scenario (10). The pentanes plus production projections provide the volumes of diluent expected to be produced and imported. Most of the diluent demand in Canada is fulfilled by imports. The Canadian production comes from field condensate production, condensate production at gas processing facilities, and production from refineries. Field condensate production is the largest portion of domestic production, followed by condensate production at gas processing facilities, small volumes of production from refinery operations. Only domestic production of field condensate and condensate production at gas processing facilities are considered when calculating emissions because these operations result in the condensate being the significant product or co-products.

The emission factors for conventional light crude oil were used to determine the emissions from the production of condensate. The volume of condensate produced domestically and resulting from field production and gas processing operations is multiplied by the emission factor to determine the upstream emissions associated with the diluent.

Annex C – Limitations of the Analysis

There are a number of limitations with the approach taken to discuss whether the construction of the Line 3 replacement pipeline could enable more crude oil production and, therefore, upstream GHG emissions, than a case in which no additional pipeline capacity was built. These include:

- The data and sources used in this report are limited to those that are publicly available. For example, some specifics around supply costs and performance of oil sands projects are estimates based on third-party analysis.
- This analysis relies primarily on data and projections from the Government of Canada, including the NEB's *Canada's Energy Future 2016* document for production projections. It is important to consider that the NEB's forecast includes only policies and programs that are law at the time of writing are included in the projections. Any new policies under consideration, or new policies developed after the summer of 2015 are not included.
- Impacts of the Project on oil markets, prices or production were not modelled for this analysis as this report is intended as a discussion of the *conditions* under which additional pipeline capacity would support greater crude oil production, and upstream GHG emissions, relative to a case in which no new pipeline capacity was built. Sophisticated modeling approaches have been employed by third parties for other pipelines, such as the study on the Energy East pipeline proposal undertaken by Navius Research for the Ontario Energy Board.

Annex D – Oil Sands and Heavy Oil Projects Under Construction (2015)

Type	Company	Project	Status	Planned bitumen/SCO capacity (bbl/d)	Planned dilbit/SCO capacity (bbl/d)	Estimated Start-up
<i>In Situ</i>	Brion Energy	Mackay River Phase 1	Construction	35,000	50,000	2016
<i>In Situ</i>	Cenovus/ConocoPhillips	Foster Creek Phase G	Construction	30,000	42,900	2016
<i>In Situ</i>	Cenovus/ConocoPhillips	Christina Lake Phase F	Construction	50,000	71,400	2016
<i>In Situ</i>	Japan Canada	Expansion	Construction	20,000	28,600	2016
<i>In Situ</i>	Husky Energy	Edam East & West	Construction	14,500	14,500	2016
<i>In Situ</i>	Husky Energy	Vawn	Construction	14,500	14,500	2016
<i>In Situ</i>	Sunshine Oil Sands	West Ells	Construction	5,000	7,100	2016
Mining	Canadian Natural Resources	Horizon Phase 2/3	Construction	137,000	137,000	2017
Mining	Suncor/Total/Teck	Fort Hills Phase 1	Construction	180,000	225,000	2017
<i>In Situ</i>	Cenovus/ConocoPhillips	Foster Creek Phase H	Construction delayed ^{xvii}	30,000	42,900	2018
<i>In Situ</i>	Cenovus/ConocoPhillips	Christina Lake Phase G	Construction delayed	50,000	71,400	2018
<i>In Situ</i>	Harvest Operations Corp	BlackGold Phase 1	Steaming delayed ^{xviii}	10,000	14,300	2018
Total under construction or expected				576,000	719,600	

Source: IHS (43); CanOils (44); Company Reports

^{xvii} According to IHS, Cenovus has stated that it will continue to advance two projects simultaneously through the low price period. It will first complete Foster Creek Phase G and Christina Lake Phase F before resuming construction on Foster Creek Phase H and Christina Lake Phase G expansions of these facilities. Cenovus had also commenced early construction at its Narrow Lake project, but in light of comment, it will likely advance only after prices are higher.

^{xviii} IHS notes that the project is complete, but Harvest has stated that steaming will not commence until prices rise above \$60 per barrel WTI.